

Contract DSS EMR 23440-7-9070-01SS

STEAM INJECTION EXPERIMENTS IN SCALED PHYSICAL MODELS

FINAL REPORT

(July 8, 1987—August 31, 1989)

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926 pp

MICROMEDIA



FOREWARD

This final report covers the period July 8, 1987 to June 30, 1989, of the subject project.

During the period of this report, major changes were made in the experimental apparatus, partly for improved performance and partly due to breakdown of the older equipment. Two papers were authored on the basis of the work done. These are appended as Appendix I. The emphasis is currently on horizontal well modelling within the framework of the present contract, and has pointed the future directions to take under Phase IV.

The technical assistance and ideas provided by Dr. Albert George is gratefully acknowledged. Thanks are also expressed to Dr. K.W.A. Miller, Mr. Jon Peggs and Mr. T.R. Vonde , Husky Oil Operations Ltd., for providing valuable time and assistance, as well as the materials used in this work.

The funding by Panel of Energy and Research Development (PERD) is gratefully acknowledged.

The financial assistance of CANMET/Energy Mines and Resources Canada is acknowledged, which made this research possible and contributed to the graduate program of the Department of Mining, Metallurgical and Petroleum Engineering of the University of Alberta. Two graduate students, Ms. Helen Chang and Mr. Quang Doan, are about to complete their M.Sc. degrees based upon this work. Tow final year undergraduates, Mr. Rex Matthias and Mr. Dan Downey, are planning to pursue graduate studies as a result of the interest generated by their involvement in this research.

EXECUTIVE SUMMARY

In this research, steam injection experiments were carried out in a scaled physical model, and in two types of models for horizontal wells. At the same time scaling criteria were derived for the horizontal well model and selected simulations were carried out of cyclic steam stimulation and steamflooding process in the presence of bottom water. Work was continued on the improvement of the steam injection simulator under development.

The scaled model experiments examined a variety of operating strategies for improving oil recovery when bottom water is present. These included: gas injection prior to steam, in order to promote steam segregation and prevent its channelling into the water zone, solvent injection prior to steam to open steam flow paths in the oil zone, and combinations of vertical and horizontal wells. A horizontal injector-horizontal producer combination proved to be the most desirable in the presence of bottom water, comprising 10 or 15% of the oil zone thickness. Oil recoveries for all these experiments as well as the temperature distributions are reported in this report.

During the research period, many important changes were made to the apparatus to facilitate operation and save time and money. These included: conversion of the cold storage to a freezer, design and construction of a completely new data acquisition system, (in view of the breakdown of the old system), design of a new sample collection system, replacement of the vacuum pump by a suction pump, construction of a new steam generator, as well as many other smaller improvements.

Close contact was maintained with the Saskatchewan Research Council. Consultations were held frequently with Husky Oil Operations Ltd. and PanCanadian Petroleum Ltd. to focus on problems of interest to the industry.

SOMMAIRE DES TRAVAUX EFFECTUÉS

Dans cette recherche des expériences d'injection de vapeur dans un modèle à l'échelle, et dans deux types de modèles pour puits horizontaux, ont été effectués. En même temps les critères d'échelle pour un modèle de puit horizontal ont été dérivés, et des simulations sélectionnées des procédés de stimulation cyclique par la vapeur et d'injection de vapeur dans des réservoirs avec fond d'eau ont été essayées. L'oeuvre s'est poursuivie sur l'amélioration du simulateur d'injection de vapeur en cours de développement.

Les expériences sur le modèle à l'échelle ont permis d'examiner les stratégies pour améliorer la récupération d'huile en présence d'eau de fond. Elles ont compris: l'injection de gaz avant la vapeur pour promouvoir la séparation de la vapeur et empêcher son écoulement dans la zone d'eau de fond; l'injection de solvant avant la vapeur pour ouvrir les chemins d'écoulement de la vapeur; et les combinaisons de puits verticaux et horizontaux. La combinaison injecteur horizontal-producteur horizontal s'est avérée la plus efficace en présence d'une eau de fond constituant 10% à 15% de l'épaisseur de la zone d'huile. Les récupérations d'huile pour toutes les expériences, ainsi que les distributions de températures sont rapportées dans ce rapport.

Au cours de cette période de recherche beaucoup de modifications importantes ont été apportées aux appareils expérimentaux pour faciliter les opérations et pour épargner le temps et le coût. Ils ont compris: la conversion de la chambre frigorifique en un congélateur; le dessin et la construction d'un nouveau système pour l'acquisition d'information (en raison de la panne de l'ancien système); le dessin d'un nouveau système de collection d'échantillons produits; le remplacement d'une pompe à vide par une pompe aspirante; la construction d'un nouveau générateur de vapeur, aussi que d'autres améliorations.

Un contact étroit avec le Conseil de Recherches de la Saskatchewan a été maintenu. On a aussi été maintenu les consultations fréquemment avec Husky Oil Operations Ltd. et PanCanadian Petroleum Ltd. pour se focaliser sur les problèmes d'intérêt pour l'industrie.

WORK STATEMENT

EXPERIMENTAL WORK

Task 1 Unchanged

Horizontal well fluid flow, in the vicinity of the well, using a wellbore model:

A transparent, rectangular model, with a horizontal well placed within will be designed, fabricated, and used to simulate flow in the immediate vicinity of the wellbore. No information is currently available on this aspect of horizontal wells. Flow into a horizontal well is not radial, as often assumed in mathematical studies. The transparent nature of the model will permit a visual record of flow.

Task 2 Unchanged

Experimental runs in the above model:

The model described above will be used for air-water runs to determine flow behaviour for a number of boundary conditions (pressure specifications). At least six experiments will be conducted. The use of air instead of steam will reflect the flow behaviour of steam for the case where steam condensation is minimal, i.e. in a steam zone. The model runs will examine two-phase flow characteristics for various air-water rates and horizontal well placements.

Task 3 Unchanged

Design and fabrication of a high pressure, linear horizontal well model:

A linear model will be designed and constructed, with the placement of an axial horizontal well. Unlike the model in Task 1, this model will be employed for scaled, high pressure experiments, using water and steam, and water, oil, and steam. This model is a natural extension of the visual model under Task 1. The scaled experiments will investigate selected experiments done under Task 2 to determine how much difference scaling makes.

Task 4

Task 4 to be replaced by:

"Solvent-Gas Steamfloods"

Exploratory work showed that injection of a small amount of gas, followed by solvent injection, and then a steamflood, is highly effective for bottom water situations. It is proposed to conduct five runs of this type.

Task 5

Horizontal well steamfloods in the low pressure model:

We have gained experience in horizontal well steamfloods in the existing low pressure scaled model. Under this task, we plan to study the relative effectiveness of horizontal/vertical well combinations. At least five runs are planned. The work done under Tasks 1 to 3, coupled with mathematical studies, will permit proper scaling criteria for the horizontal well runs. Three of the runs to be conducted will utilize horizontal wells as injectors as well as producers. The variable to be studied is the placement of the wells in the vertical plane.

Task 6

Task 6 to be replaced by:

"Solvent-Steamfloods"

Experimental runs using a small amount of solvent with steam will be carried out. This will be done in situations with or without bottom water. At least 12 runs will be conducted.

Task 7 Unchanged

Gas injection experiments in the low pressure model:

A notable finding of our previous work is that when mobile water is present under the oil zone ("bottom water"), a gas saturation in the upper part of the oil zone improves steamflood efficiency. The questions regarding the extent of a gas saturation, and its

placement are still to be resolved, and will be the subject of this task. At least three experiments of this type are planned.

Task 8 Eliminated

Multi-layer Steamfloods in the low pressure model:

The basic objective of these runs is to determine how adverse is the effect of permeability variation in the vertical direction on the efficiency of the steamflood. For this purpose, the scaled model will be packed with layers of two different permeabilities, differing by a factor of 10. At least three runs are planned. In one case the high permeability layer will be placed on top (to reinforce gravity segregation of steam), while in the other two, it will be placed at the base (to impede gravity segregation).

Task 9 Unchanged

Use of barriers in bottom water steamfloods in the low pressure model:

The ultimate - though largely impractical - solution to bottom water is to place an impermeable barrier between the oil and water layers. Such barriers can be created to a limited extent by use of chemicals. In at least two experiments, a physical barrier will be placed at the base of the oil zone, with a circular geometry, encompassing approximately 25% of the flow area, to simulate limited injection of a polymer at the oil-water contact. These experiments will provide an upper bound on the efficacy of "perfect" barriers.

Task 10+11

Tasks 10 and 11 to be replaced by:

"Waterfloods in the Low Pressure Model"

The runs under Tasks 10 and 11 were linked to Task 6, which is proposed to be replaced by the new work schedule, as noted above. The waterfloods will provide us with base information to compare the steamfloods with.

Task 11

Gas-steam runs in the high pressure model:

Presence of gas can accelerate oil recovery by steam, as shown by our past experimental and mathematical work. The response is different for condensable and non-condensable gases.

In these runs, it is proposed to use alternating slugs of gas and steam. Carbon dioxide and nitrogen will be used. At least four runs are planned. The model will be used in both horizontal and vertical positions. (See Amendments under Task 10+11).

Task 12 Unchanged

Final Report and Presentation at CANMET, Ottawa:

The research conducted will be described in a final report, and presented at the Energy Research Laboratories/CANMET, in Ottawa.

THEORETICAL WORK

Task 13 Unchanged

Use of the present simulator to determine the relative merits of the low and high pressure models, and examine the effects of partial scaling of the physical models in the two cases:

A versatile steamflood simulator has been developed under the present contract. This multicomponent steam simulator will be used to determine the effect of partial scaling of the models. This will be accomplished by simulating the prototype and the model, separately, and comparing the results. In this manner, the more significant scaling groups will be isolated. Work will be necessary on the simulator to adapt it for studies of this type.

Task 14 Unchanged

Overall assessment of steam injection methods developed experimentally and theoretically for application to marginal reservoirs:

The research conducted, experimental and theoretical, will be evaluated on a global basis to determine which of the steam processes tested is likely to succeed in the field. At least two reservoirs will be identified, where one or more of the processes developed might be applicable. It is hoped that as a result, a field test would be initiated.

Task 15: New

"Industry Interaction"

We maintain rapport with the oil companies engaged in steam injection operations, in order to make our work as relevant to industry needs as possible. Furthermore, such interaction makes the industry cognizant of CANMET's role in industrial development.

Table of Contents

<u>Chapter</u>	<u>Page</u>
Foreward _____	i
Executive Summary _____	ii
Sommaire des Travaux Effectués _____	iii
Work Statement _____	iv
List of Tables _____	xv
List of Figures _____	xviii
List of Plates _____	xli
Nomenclature (Part I) _____	xlii
Nomenclature (Part II) _____	xliv
 Part I: Scaled Model Steamflooding Experiments	
1. Introduction _____	1
2. Literature Review _____	3
Scaled Model Studies of Steam Injection Processes _____	4
Experimental Approaches to Steam Injection _____	4
High Pressure and Low Pressure Scaled Models _____	6
Studies of Thin, Bottom Water Reservoirs _____	10
Incorporation of Solvent with Steam Injection Processes _____	12
Dispersion and Diffusion of Solvents in a Porous Medium _____	12
Non-Thermal Miscible Displacement Processes _____	12
Solvent Scaling Criteria _____	15
Incorporation of Solvent Injection into Thermal Recovery Methods _____	15
Asphaltene Flocculation _____	20
Horizontal Well Study _____	20

The Productivity of Horizontal Wells	22
Homogeneous and Isotropic Reservoirs	22
The Influence of Anisotropy	23
Water Coning and Cresting	24
Well Flow Behaviour	28
Early Time Flow Geometry of a Horizontal Well	28
Late Time Flow Geometry of a Horizontal Well	31
Gravity Drainage	33
Well Patterns	35
3. Scaling Parameters and Calculations	41
Development of Scaling Parameters for the Low Pressure Model	41
Unscaled Parameters	41
Scaling Procedures	43
Calculation of Parametric Values for the Aberfeldy Low Pressure Model ..	46
Prototype and Model Correlations	46
Length Scale Selection	48
Model Pressure Scaling	48
Model Temperature Scaling	49
Time Scale Determination	52
Flow Rate Scaling	53
Scaling of Steam Quality	54
Scaling of Model Oil Viscosity	55
Scaling of Model Permeability	55
Scaling of Vertical Wells	56
4. Experimental Apparatus and Procedure	59
Experimental Apparatus	59
Physical Model	59

Vertical and Horizontal Wells	64
Porous Media	66
Model Cart, Rail System and Cold Storage Compartment	66
Fluid Injection System	66
Fluid Collection System	67
Data Acquisition System	71
Model Fluids	74
Selection of Model Oil for the Aberfeldy Reservoir	74
Solvent Selection	74
Preparation of the Experimental Model	76
Model Packing Procedure	76
Fluid Saturation Process	79
Preparation of A Bottom Water Model	80
Creation of a Gas Zone	80
Conducting Experiments in the Model	81
Waterflood	82
Steamflood in a Homogeneous Model	82
Solvent-Steamflood	82
Bottom Water Runs	83
Gas Injection Runs	83
Apparatus Clean Up	83
Data Analysis	84
5. Discussion of the Results	85
Presentation of of the Results	85
Steamflood versus Solvent-Steamflood Process	91
Typical Steamflood History in a Bottom Water Reservoir	93
Base Experiments for Comparison Purposes	101

Continuous Solvent Flood	101
Solvent-Steamflood	107
Steamflood of a Bottom Water Model With Prior Gas Injection	126
Effect of Solvent Slug Size on Oil Recovery by a Steamflood	140
Effect of Bottom Water Thickness on Steamflood Response	159
Effect of Bottom Water Thickness on Solvent-Steamflood Response	162
Role of Gas Injection in Steamflooding	196
Gas Injection in a Steamflood	198
Gas Injection Prior to Steam Injection with Bottom Water	198
Gas Injection with Solvent and Steam Injection	199
Gas Injection Prior to Solvent & Steam Injection with Bottom Water	213
Effect of Injection-Production Interval Locations	231
Use of a Physical Barrier in a Bottom Water Steamflood	235
Effectiveness of Waterflooding Prior to Solvent and Steam Injection	250
Heat Flow Analysis	267
Lauwerier Equation	267
Comparison of Marx-Langenheim and Mandl-Volek Models	270
A. Marx-Langenheim Theory	270
B. Mandl-Volek Theory	272
Heat Loss Analysis	273
Effect of Vertical/Horizontal Well Combinations	281
Experimental Limitations and Sources of Error	228

Part II: Scaled Model Steamflooding Experiments

Introduction	290
6. Literature Review	292
Scaled Model Studies of Steam Processes	292

Scaled Model Studies of Horizontal Wells	295
7. Development of Scaling Criteria for Physical Model	301
Flow of Reservoir Fluids From Porous Medium to Horizontal Well	301
Flow of Reservoir Fluids Within the Horizontal Well	311
8. Experimental Apparatus and Procedure	316
Experimental Apparatus	316
High-Pressure Physical Model	316
Visual Model	317
Experiment Procedure	321
High-Pressure Physical Model	321
Visual Model	325
9. Experimental Results and Discussion	326
Visual Model	326
High-Pressure Physical Model	335
10. Numerical Simulation	346
11. Conclusions	353
12. References	357
Appendix A — Temperature Profiles	366
Appendix B — Computer Programs Used in Heat Flow Analysis	659
Appendix C — Detailed Laboratory Manual	669
Appendix D — Contour Plotting Programs and Graphic Procedures	685
Appendix E — List of Suppliers and Materials	708
Appendix F — Initial and Boundary Conditions for Reservoir Flow	713
Appendix G — Equations in Dimensionless Form	715
Appendix H — Dimensionless Conservation	718
Appendix I — Papers Presented	721

"Effect of Bottom and Top Water on Cyclic Steam Stimulation Response"	722
"Role of Foam, Non-Newtonian Flow, and Thermal Upgrading in Steam Injection"	738
"Effect of Wellbore Steam Quality Variation on Steamflooding Thick Formation"	748
"Scaled Model Studies of Solvent-Steam Injections Under Bottom Water Conditions"	756
"Scaled Model Studies of Solvent-Steam Injection"	770

List of Tables

<u>Table</u>	<u>Page</u>
2.1 List of Horizontal Well Projects for Heavy Oil Recovery _____	21
3.1 Scaling Parameters for Steam Processes _____	44
3.2 Summary of Scaling Parameters for Steam Processes _____	47
3.3 Prototype and Model Scaling Values _____	51
3.4 Scaling Set for Steam Processes _____	58
4.1 Temperature versus Oil Viscosity Data for Prototype and Ideal Model Oil ____	74
4.2 Prototype and Model Values for the Aberfeldy Reservoir _____	30
4.3 Prototype and Model Scaling Values _____	34
4.4 Steam Enthalpy at Various Model Pressures _____	40
5.1 List and Description of Solvent and Steam Injection Experiments _____	86
5.2 Experimental Data for Run 39: Steamflood in Bottom Water Model _____	95
5.3 Experimental Data for Run 40: Solvent Flood in Homogeneous Model ____	102
5.4 Experimental Data for Run 44: Solvent-Steamflood in Homogeneous Model_	109
5.5 Experimental Data for Run 45: Solvent-Steamflood in Homogeneous Model_	114
5.6 Experimental Data for Run 46: Solvent-Steamflood in Homogeneous Model_	119
5.7 Experimental Data for Run 60: Gas Injection Prior to a Steamflood in Homogeneous Model _____	128
5.8 Experimental Data for Run 61: Gas Injection Prior to a Steamflood in Homogeneous Model _____	133
5.9 Experimental Data for Run 65: Solvent-Steamflood in Bottom Water Model _____	142
5.10 Experimental Data for Run 66: Solvent-Steamflood in Homogeneous Model _____	149
5.11 Experimental Data for Run 67: Solvent-Steamflood in Homogeneous Model _____	154
5.12 Experimental Data for Run 49: Solvent-Steamflood in Bottom Water Model _____	166

5.13	Experimental Data for Run 50: Solvent-Steamflood in Bottom Water Model	171
5.14	Experimental Data for Run 51: Solvent-Steamflood in Bottom Water Model	176
5.15	Experimental Data for Run 53: Solvent-Steamflood in Bottom Water Model	181
5.16	Experimental Data for Run 54: Solvent-Steamflood in Bottom Water Model	186
5.17	Experimental Data for Run 55: Gas Injection Prior to a Solvent-Steamflood in Homogeneous Model	202
5.18	Experimental Data for Run 56: Gas Injection Prior to a Solvent-Steamflood in Homogeneous Model	207
5.19	Experimental Data for Run 58: Gas Injection Prior to a Solvent-Steamflood in Bottom Water Model	215
5.20	Experimental Data for Run 59: Gas Injection Prior to a Solvent-Steamflood in Bottom Water Model	220
5.21	Experimental Data for Run 62: Gas Injection Prior to a Solvent-Steamflood in Bottom Water Model	225
5.22	Experimental Data for Run 63: Steamflood in Bottom Water Model With a Partial Barrier	238
5.23	Experimental Data for Run 64: Steamflood in Bottom Water Model With a Partial Barrier	243
5.24	Experimental Data for Run 47A: Waterflood Prior to a Solvent-Steamflood in Homogeneous Model	252
5.25	Experimental Data for Run 47B: Solvent-Steamflood Following a Waterflood in Homogeneous Model	253
5.26	Experimental Data for Run 48A: Waterflood Prior to a Solvent-Steamflood in Homogeneous Model	261
5.27	Experimental Data for Run 48B: Solvent-Steamflood Following a Waterflood in Homogeneous Model	262
5.28	Heat Flow Analysis of Model Using Lauwerier Equation (Run 26): 1/2 of Injection in Top Portion and 1/2 of Injection in Bottom Portion	277
5.29	Heat Flow Analysis of Model Using Lauwerier Equation (Run 26): 3/4 of Injection in Top Portion and 1/4 of Injection in Bottom Portion	278
5.30	Comparison of Marx-Langenheim and Mandl-Volek Models of Formation Heating by Steam Injection for the Low Pressure Model in Run 26	279

5.31	Analysis of Heat Loss Occurring During a Base Steamflood (Run 26)	280
5.32	Run 74. Steam Injection of a Homogeneous Model using a Vertical Injector and Horizontal Producer	282
5.33	Run 75. Steam Injection of a Homogeneous Model using a Horizontal Injector and Horizontal Producer	283
5.34	Run 76. Steam Injection of a Homogeneous Model using a Horizontal Injector and Vertical Producer	284
5.35	Run 77. Steam Injection of a Homogeneous Model using a Vertical Injector and Vertical Producer	285
7.1	Constraints and Constitutive Relationships	305
7.2	Mass Balance of Oil Written in Terms of $M_D = M/M_R$	308
7.3	Scaling Criteria for Flow from Reservoir to Horizontal Well	310
9.1	Summary of Experiments	328
9.2	Production Data for Two Types of Visual Runs	329
9.3	Production Data for Run HP2	337
9.4	Production Data for Run HP4	341

List of Figures

Figure	Page
2.1 Water Coning Toward a Vertical Well & Cresting Toward a Horizontal Well	25
2.2 Schematic of Potential Flow to a Horizontal Well	29
2.3 Dupuit-Forcheimer Approximation of the Shape of a Water Crest	44
2.4(a) Intermediate-Time Linear Flow	44
2.4(b) Late-Intermediate-Time Linear Flow	44
2.4(c) Late-Time Linear Flow	44
2.5 Steam Assisted Gravity Drainage Concept Applied to a Horizontal Well Pair	34
2.6 Steam Growth Chamber Above Adjacent Horizontal Wells	34
2.7 Different Well Configuration Schemes SAGD	36
2.8 A Schematic Diagram of Various Horizontal Well Configurations	38
2.9 Combination of Horizontal Well Patterns	38
4.1 Schematic Diagram of Apparatus	60
4.2 Schematic Diagram of Thermocouple Positions	65
4.3 Schematic Diagram of the Produced Fluid Collection System	69
4.4 Viscosity vs. Temperature Profiles for the Ideal Model and Actual Selected (Faxam-100) Model Oil	75
4.5 Viscosity of the Mixture of Faxam-100 and Heavy Virgin Naphtha vs. HVN Concentration	77
4.6 The Wygal Particle Distributor	78
5.1 Map of Experimental Runs Conducted During the Research Project	90
5.2 Schematic Diagram of a Steamflood Process	92
5.3 Schematic Diagram of a Solvent-Steamflood Process	93
5.4 Run 39: Cumulative Oil Recovery Vs. Pore Volumes Injected	96
5.5 Run 39: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	97

5.6	Run 39: Instantaneous Produced WOR Vs. Cumulative Volume Injected _____	98
5.7	Run 39: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	99
5.8	Run 40: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	104
5.9	Run 40: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	105
5.10	Run 44: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	110
5.11	Run 44: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	111
5.12	Run 44: Instantaneous Produced WOR Vs. Cumulative Volume Injected _	112
5.13	Run 44: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	113
5.14	Run 45: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	115
5.15	Run 45: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	116
5.16	Run 45: Instantaneous Produced WOR Vs. Cumulative Volume Injected _	117
5.17	Run 45: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	118
5.18	Run 46: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	120
5.19	Run 46: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	121
5.20	Run 46: Instantaneous Produced WOR Vs. Cumulative Volume Injected _	122
5.21	Run 46: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	123
5.22	Run 60: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	129
5.23	Run 60: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	130
5.24	Run 60: Instantaneous Produced WOR Vs. Cumulative Volume Injected _	131
5.25	Run 60: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	132
5.26	Run 61: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	134
5.27	Run 61: Oleic Phase in Each Sample Vs. Cumulative Volume Injected _____	135
5.28	Run 61: Instantaneous Produced WOR Vs. Cumulative Volume Injected _	136
5.29	Run 61: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced _____	137
5.30	Comparison of Steamflood Run 39 & Gas Injection Prior to a Steamflood Run 61 Recoveries Performed in a Bottom Water Model _____	139
5.31	Run 65: Cumulative Oil Recovery Vs. Pore Volumes Injected _____	143

5.32	Run 65: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	144
5.33	Run 65: Instantaneous Produced WOR Vs. Cumulative Volume Injected	145
5.34	Run 65: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	146
5.35	Run 66: Cumulative Oil Recovery Vs. Pore Volumes Injected	150
5.36	Run 66: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	151
5.37	Run 66: Instantaneous Produced WOR Vs. Cumulative Volume Injected	152
5.38	Run 66: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	153
5.39	Run 66: Cumulative Oil Recovery Vs. Pore Volumes Injected	155
5.40	Run 66: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	156
5.41	Run 66: Instantaneous Produced WOR Vs. Cumulative Volume Injected	157
5.42	Run 66: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	158
5.43	Comparison of the Effect of Solvent Slug Size on Solvent-Steamflood Recoveries for Runs 45, 66 & 67	160
5.44	Run 49: Cumulative Oil Recovery Vs. Pore Volumes Injected	167
5.45	Run 49: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	168
5.46	Run 49: Instantaneous Produced WOR Vs. Cumulative Volume Injected	169
5.47	Run 49: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	170
5.48	Run 50: Cumulative Oil Recovery Vs. Pore Volumes Injected	172
5.49	Run 50: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	173
5.50	Run 50: Instantaneous Produced WOR Vs. Cumulative Volume Injected	174
5.51	Run 50: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	175
5.52	Run 51: Cumulative Oil Recovery Vs. Pore Volumes Injected	177
5.53	Run 51: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	178
5.54	Run 51: Instantaneous Produced WOR Vs. Cumulative Volume Injected	179
5.55	Run 51: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	180
5.56	Run 53: Cumulative Oil Recovery Vs. Pore Volumes Injected	182
5.57	Run 53: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	183

5.58	Run 53: Instantaneous Produced WOR Vs. Cumulative Volume Injected	184
5.59	Run 53: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	185
5.60	Run 54: Cumulative Oil Recovery Vs. Pore Volumes Injected	187
5.61	Run 54: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	188
5.62	Run 54: Instantaneous Produced WOR Vs. Cumulative Volume Injected	189
5.63	Run 54: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	190
5.64	Total Oil Recovery Vs. Bottom Water Thickness for Solvent-Steamfloods	194
5.65	Comparison of Steamflood Run 39 & Solvent-Steamflood Run 54 Recoveries Performed in a Bottom Water Model	195
5.66	Run 55: Cumulative Oil Recovery Vs. Pore Volumes Injected	203
5.67	Run 55: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	204
5.68	Run 55: Instantaneous Produced WOR Vs. Cumulative Volume Injected	205
5.69	Run 55: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	206
5.70	Run 56: Cumulative Oil Recovery Vs. Pore Volumes Injected	208
5.71	Run 56: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	209
5.72	Run 56: Instantaneous Produced WOR Vs. Cumulative Volume Injected	210
5.73	Run 56: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	211
5.74	Comparison of Solvent-Steamflood Run 45 & Gas Injection Prior to Solvent Steamflood Run 56 Recoveries Performed in a Homogeneous Model	212
5.75	Run 58: Cumulative Oil Recovery Vs. Pore Volumes Injected	216
5.76	Run 58: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	217
5.77	Run 58: Instantaneous Produced WOR Vs. Cumulative Volume Injected	218
5.78	Run 58: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	219
5.79	Run 59: Cumulative Oil Recovery Vs. Pore Volumes Injected	221
5.80	Run 59: Oleic Phase in Each Sample Vs. Cumulative Volume Injected	222
5.81	Run 59: Instantaneous Produced WOR Vs. Cumulative Volume Injected	223
5.82	Run 59: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	224
5.83	Run 62: Cumulative Oil Recovery Vs. Pore Volumes Injected	226

5.84	Run 62: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	227
5.85	Run 62: Instantaneous Produced WOR Vs. Cumulative Volume Injected	228
5.86	Run 62: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	229
5.87	Comparison of Solvent-Steamflood Run 50 & Gas Injection Prior to Solvent Steamflood Run 58 Recoveries Performed in a Bottom Water Model	232
5.88	Comparison of Effect of Injection-Production Interval Locations Runs 49 & 50	233
5.89	Schematic of Partial Barrier Installed in a Bottom Water Model	236
5.90	Run 63: Cumulative Oil Recovery Vs. Pore Volumes Injected	239
5.91	Run 63: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	240
5.92	Run 63: Instantaneous Produced WOR Vs. Cumulative Volume Injected	241
5.93	Run 63: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	242
5.94	Run 64: Cumulative Oil Recovery Vs. Pore Volumes Injected	244
5.95	Run 64: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	245
5.96	Run 64: Instantaneous Produced WOR Vs. Cumulative Volume Injected	246
5.97	Run 64: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	247
5.98	Comparison of Recoveries of a Solvent-Steamflood With Bottom Water Run 50 & a Steamflood With a Partial Bottom Water Barrier Run 64	249
5.99	Run 47: Cumulative Oil Recovery Vs. Pore Volumes Injected	254
5.100	Run 47: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	255
5.101	Run 47: Instantaneous Produced WOR Vs. Cumulative Volume Injected	256
5.102	Run 47: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	257
5.103	Run 48: Cumulative Oil Recovery Vs. Pore Volumes Injected	263
5.104	Run 48: Oleic Phase in Each Sample Vs.Cumulative Volume Injected	264
5.105	Run 48: Instantaneous Produced WOR Vs. Volume Injected	265
5.106	Run 48: Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced	266
5.107	Schematic Diagram of the Marx-Langenheim Model for Reservoir Heating by Steam Injection	276

5.108	Comparison of Instantaneous Oil Recoveries from Steamfloods in Homogeneous Horizontal Well Models for Runs 74, 75, 76 and 77	286
5.109	Comparison of Cumulative Oil Recoveries from Steamfloods in Homogeneous Horizontal Well Models for Runs 74, 75, 76 and 77	287
7.1	Sketch of Control Volume for Reservoir Flow	304
7.2	Sketch of Control volume for Horizontal Well Flow	315
8.1	Apparatus Setup for High-Pressure Model Runs	318
8.2	Horizontal Well Physical Model	319
8.3	Viscosity-Temperature Relationship of Aberfeldy Oil	320
8.4	Apparatus Setup for Visual Model Runs	322
9.1	Fluid Prod. Rate vs. Vol. of Gas Inj. (Vertical Injector, Horizontal Producer)	330
9.2	Fluid Prod. Rate vs. Vol. of Gas Inj. (Horizontal Injector, Vertical Producer)	331
9.3	Fluid Prod. Rate vs. Vol. of Gas Inj. (Gas Inj. Rate=1.76 ml/s)	332
9.4	Fluid Prod. Rate vs. Vol. of Gas Inj. (Gas Inj. Rate=2.56 ml/s)	333
9.5	Fluid Prod. Rate vs. Vol. of Gas Inj. (Gas Inj. Rate=5.68 ml/s)	334
9.6	Well Press. Diff. vs. Volum of Steam Injected (Run HP 2)	338
9.7	Inst. Fluid Prod. Rate vs. Vol. of Steam Inj. (Run HP 2)	339
9.8	Cum. Fluid Prod. Rate vs. Vol. of Steam Inj. (Run HP 2)	340
9.9	Well Press. Diff. vs. Volum of Steam Injected (Run HP 4)	342
9.10	Inst. Fluid Prod. Rate vs. Vol. of Steam Inj. (Run HP 4)	343
9.11	Cum. Fluid Prod. Rate vs. Vol. of Steam Inj. (Run HP 4)	344

Figures - Appendix A

A.1	Run 39: Top View Temperature Profile at 0.25 Pore Volumes Injected	367
A.2	Run 39: Top View Temperature Profile at 0.50 Pore Volumes Injected	368
A.3	Run 39: Top View Temperature Profile at	

	0.75 Pore Volumes Injected _____	369
A.4	Run 39: Top View Temperature Profile at 1.00 Pore Volumes Injected _____	370
A.5	Run 39: Top View Temperature Profile at 1.25 Pore Volumes Injected _____	371
A.6	Run 39: Top View Temperature Profile at 1.50 Pore Volumes Injected _____	372
A.7	Run 39: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected _____	373
A.8	Run 39: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected _____	374
A.9	Run 39: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected _____	375
A.10	Run 39: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected _____	376
A.11	Run 40: Top View Temperature Profile at 0.25 Pore Volumes Injected _____	377
A.12	Run 40: Top View Temperature Profile at 0.50 Pore Volumes Injected _____	378
A.13	Run 40: Top View Temperature Profile at 0.75 Pore Volumes Injected _____	379
A.14	Run 40: Top View Temperature Profile at 1.00 Pore Volumes Injected _____	380
A.15	Run 40: Top View Temperature Profile at 1.25 Pore Volumes Injected _____	381
A.16	Run 40: Top View Temperature Profile at 1.50 Pore Volumes Injected _____	382
A.17	Run 40: Top View Temperature Profile at 1.75 Pore Volumes Injected _____	383
A.18	Run 40: Top View Temperature Profile at 2.00 Pore Volumes Injected _____	384
A.19	Run 40: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected _____	385
A.20	Run 40: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected _____	386

A.21	Run 40: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	387
A.22	Run 40: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	388
A.23	Run 44: Top View Temperature Profile at 0.25 Pore Volumes Injected	389
A.24	Run 44: Top View Temperature Profile at 0.50 Pore Volumes Injected	390
A.25	Run 44: Top View Temperature Profile at 0.75 Pore Volumes Injected	391
A.26	Run 44: Top View Temperature Profile at 1.00 Pore Volumes Injected	392
A.27	Run 44: Top View Temperature Profile at 1.25 Pore Volumes Injected	393
A.28	Run 44: Top View Temperature Profile at 1.50 Pore Volumes Injected	394
A.29	Run 44: Top View Temperature Profile at 1.75 Pore Volumes Injected	395
A.30	Run 44: Top View Temperature Profile at 2.00 Pore Volumes Injected	396
A.31	Run 44: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	397
A.32	Run 44: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	398
A.33	Run 44: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	399
A.34	Run 44: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	400
A.35	Run 45: Top View Temperature Profile at 0.25 Pore Volumes Injected	401
A.36	Run 45: Top View Temperature Profile at 0.50 Pore Volumes Injected	402
A.37	Run 45: Top View Temperature Profile at 0.75 Pore Volumes Injected	403
A.38	Run 45: Top View Temperature Profile at 1.00 Pore Volumes Injected	404

A.39	Run 45: Top View Temperature Profile at 1.25 Pore Volumes Injected	405
A.40	Run 45: Top View Temperature Profile at 1.50 Pore Volumes Injected	406
A.41	Run 45: Top View Temperature Profile at 1.75 Pore Volumes Injected	407
A.42	Run 45: Top View Temperature Profile at 2.00 Pore Volumes Injected	408
A.43	Run 45: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	409
A.44	Run 45: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	410
A.45	Run 45: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	411
A.46	Run 45: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	412
A.47	Run 46: Top View Temperature Profile at 0.25 Pore Volumes Injected	413
A.48	Run 46: Top View Temperature Profile at 0.50 Pore Volumes Injected	414
A.49	Run 46: Top View Temperature Profile at 0.75 Pore Volumes Injected	415
A.50	Run 46: Top View Temperature Profile at 1.00 Pore Volumes Injected	416
A.51	Run 46: Top View Temperature Profile at 1.25 Pore Volumes Injected	417
A.52	Run 46: Top View Temperature Profile at 1.50 Pore Volumes Injected	418
A.53	Run 46: Top View Temperature Profile at 1.75 Pore Volumes Injected	419
A.54	Run 46: Top View Temperature Profile at 2.00 Pore Volumes Injected	420
A.55	Run 46: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	421
A.56	Run 46: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	422

A.57	Run 46: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	423
A.58	Run 46 : Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	524
A.59	Run 60: Top View Temperature Profile at 0.25 Pore Volumes Injected	425
A.60	Run 60: Top View Temperature Profile at 0.50 Pore Volumes Injected	426
A.61	Run 60: Top View Temperature Profile at 0.75 Pore Volumes Injected	427
A.62	Run 60: Top View Temperature Profile at 1.00 Pore Volumes Injected	428
A.63	Run 60: Top View Temperature Profile at 1.25 Pore Volumes Injected	429
A.64	Run 60: Top View Temperature Profile at 1.50 Pore Volumes Injected	430
A.65	Run 60: Top View Temperature Profile at 1.75 Pore Volumes Injected	431
A.66	Run 60: Top View Temperature Profile at 2.00 Pore Volumes Injected	432
A.67	Run 60: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	433
A.68	Run 60: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	434
A.69	Run 60: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	435
A.70	Run 60: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	436
A.71	Run 61: Top View Temperature Profile at 0.25 Pore Volumes Injected	347
A.72	Run 61: Top View Temperature Profile at 0.50 Pore Volumes Injected	438
A.73	Run 61: Top View Temperature Profile at 0.75 Pore Volumes Injected	439
A.74	Run 61: Top View Temperature Profile at 1.00 Pore Volumes Injected	440

A.75	Run 61: Top View Temperature Profile at 1.25 Pore Volumes Injected	441
A.76	Run 61: Top View Temperature Profile at 1.50 Pore Volumes Injected	442
A.77	Run 61: Top View Temperature Profile at 1.75 Pore Volumes Injected	443
A.78	Run 61: Top View Temperature Profile at 2.00 Pore Volumes Injected	444
A.79	Run 61: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	445
A.80	Run 61: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	446
A.81	Run 61: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	447
A.82	Run 61: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	448
A.83	Run 65: Top View Temperature Profile at 0.25 Pore Volumes Injected	449
A.84	Run 65: Top View Temperature Profile at 0.50 Pore Volumes Injected	450
A.85	Run 65: Top View Temperature Profile at 0.75 Pore Volumes Injected	451
A.86	Run 65: Top View Temperature Profile at 1.00 Pore Volumes Injected	452
A.87	Run 65: Top View Temperature Profile at 1.25 Pore Volumes Injected	453
A.88	Run 65: Top View Temperature Profile at 1.50 Pore Volumes Injected	454
A.89	Run 65: Top View Temperature Profile at 1.75 Pore Volumes Injected	455
A.90	Run 65: Top View Temperature Profile at 2.00 Pore Volumes Injected	546
A.91	Run 65: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	457
A.92	Run 65: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	458

A.93	Run 65: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	459
A.94	Run 65: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	460
A.95	Run 66: Top View Temperature Profile at 0.25 Pore Volumes Injected	461
A.96	Run 66: Top View Temperature Profile at 0.50 Pore Volumes Injected	462
A.97	Run 66: Top View Temperature Profile at 0.75 Pore Volumes Injected	463
A.98	Run 66: Top View Temperature Profile at 1.00 Pore Volumes Injected	464
A.99	Run 66: Top View Temperature Profile at 1.25 Pore Volumes Injected	465
A.100	Run 66: Top View Temperature Profile at 1.50 Pore Volumes Injected	466
A.101	Run 66: Top View Temperature Profile at 1.75 Pore Volumes Injected	467
A.102	Run 66: Top View Temperature Profile at 2.00 Pore Volumes Injected	468
A.103	Run 66: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	469
A.104	Run 66: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	470
A.105	Run 66: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	471
A.106	Run 66: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	472
A.107	Run 67: Top View Temperature Profile at 0.25 Pore Volumes Injected	473
A.108	Run 67: Top View Temperature Profile at 0.50 Pore Volumes Injected	474
A.109	Run 67: Top View Temperature Profile at 0.75 Pore Volumes Injected	475
A.110	Run 67: Top View Temperature Profile at 1.00 Pore Volumes Injected	476

A.111	Run 67: Top View Temperature Profile at 1.25 Pore Volumes Injected	477
A.112	Run 67: Top View Temperature Profile at 1.50 Pore Volumes Injected	478
A.113	Run 67: Top View Temperature Profile at 1.75 Pore Volumes Injected	479
A.114	Run 67: Top View Temperature Profile at 2.00 Pore Volumes Injected	480
A.115	Run 67: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	481
A.116	Run 67: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	482
A.117	Run 67: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	483
A.118	Run 67: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	484
A.119	Run 49: Top View Temperature Profile at 0.25 Pore Volumes Injected	485
A.120	Run 49: Top View Temperature Profile at 0.50 Pore Volumes Injected	486
A.121	Run 49: Top View Temperature Profile at 0.75 Pore Volumes Injected	487
A.122	Run 49: Top View Temperature Profile at 1.00 Pore Volumes Injected	488
A.123	Run 49: Top View Temperature Profile at 1.25 Pore Volumes Injected	489
A.124	Run 49: Top View Temperature Profile at 1.50 Pore Volumes Injected	490
A.125	Run 49: Top View Temperature Profile at 1.75 Pore Volumes Injected	491
A.126	Run 49: Top View Temperature Profile at 2.00 Pore Volumes Injected	492
A.127	Run 49: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	493
A.128	Run 49: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	494

A.129	Run 49: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	495
A.130	Run 49: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	496
A.131	Run 50: Top View Temperature Profile at 0.25 Pore Volumes Injected	497
A.132	Run 50: Top View Temperature Profile at 0.50 Pore Volumes Injected	498
A.133	Run 50: Top View Temperature Profile at 0.75 Pore Volumes Injected	499
A.134	Run 50: Top View Temperature Profile at 1.00 Pore Volumes Injected	500
A.135	Run 50: Top View Temperature Profile at 1.25 Pore Volumes Injected	501
A.136	Run 50: Top View Temperature Profile at 1.50 Pore Volumes Injected	502
A.137	Run 50: Top View Temperature Profile at 1.75 Pore Volumes Injected	503
A.138	Run 50: Top View Temperature Profile at 2.00 Pore Volumes Injected	504
A.139	Run 50: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	505
A.140	Run 50: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	506
A.141	Run 50: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	507
A.142	Run 50: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	508
A.143	Run 51: Top View Temperature Profile at 0.25 Pore Volumes Injected	509
A.144	Run 51: Top View Temperature Profile at 0.50 Pore Volumes Injected	510
A.145	Run 51: Top View Temperature Profile at 0.75 Pore Volumes Injected	511
A.146	Run 51: Top View Temperature Profile at 1.00 Pore Volumes Injected	512

A.147	Run 51: Top View Temperature Profile at 1.25 Pore Volumes Injected	513
A.148	Run 51: Top View Temperature Profile at 1.50 Pore Volumes Injected	514
A.149	Run 51: Top View Temperature Profile at 1.75 Pore Volumes Injected	515
A.150	Run 51: Top View Temperature Profile at 2.00 Pore Volumes Injected	516
A.151	Run 51: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	517
A.152	Run 51: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	518
A.153	Run 51: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	519
A.154	Run 51: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	520
A.155	Run 53: Top View Temperature Profile at 0.25 Pore Volumes Injected	521
A.156	Run 53: Top View Temperature Profile at 0.50 Pore Volumes Injected	522
A.157	Run 53: Top View Temperature Profile at 0.75 Pore Volumes Injected	523
A.158	Run 53: Top View Temperature Profile at 1.00 Pore Volumes Injected	524
A.159	Run 53: Top View Temperature Profile at 1.25 Pore Volumes Injected	525
A.160	Run 53: Top View Temperature Profile at 1.50 Pore Volumes Injected	526
A.161	Run 53: Top View Temperature Profile at 1.75 Pore Volumes Injected	527
A.162	Run 53: Top View Temperature Profile at 2.00 Pore Volumes Injected	528
A.163	Run 53: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	529
A.164	Run 53: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	530

A.165	Run 53: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	531
A.166	Run 53: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	532
A.167	Run 54: Top View Temperature Profile at 0.25 Pore Volumes Injected	533
A.168	Run 54: Top View Temperature Profile at 0.50 Pore Volumes Injected	534
A.169	Run 54: Top View Temperature Profile at 0.75 Pore Volumes Injected	535
A.170	Run 54: Top View Temperature Profile at 1.00 Pore Volumes Injected	536
A.171	Run 54: Top View Temperature Profile at 1.25 Pore Volumes Injected	537
A.172	Run 54: Top View Temperature Profile at 1.50 Pore Volumes Injected	538
A.173	Run 54: Top View Temperature Profile at 1.75 Pore Volumes Injected	539
A.174	Run 54: Top View Temperature Profile at 2.00 Pore Volumes Injected	540
A.175	Run 54: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	541
A.176	Run 54: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	542
A.177	Run 54: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	543
A.178	Run 54: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	544
A.179	Run 55: Top View Temperature Profile at 0.25 Pore Volumes Injected	545
A.180	Run 55: Top View Temperature Profile at 0.50 Pore Volumes Injected	546
A.181	Run 55: Top View Temperature Profile at 0.75 Pore Volumes Injected	547
A.182	Run 55: Top View Temperature Profile at 1.00 Pore Volumes Injected	548

A.183	Run 55: Top View Temperature Profile at 1.25 Pore Volumes Injected	549
A.184	Run 55: Top View Temperature Profile at 1.50 Pore Volumes Injected	550
A.185	Run 55: Top View Temperature Profile at 1.75 Pore Volumes Injected	551
A.186	Run 55: Top View Temperature Profile at 2.00 Pore Volumes Injected	552
A.187	Run 55: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	553
A.188	Run 55: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	554
A.189	Run 55: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	555
A.190	Run 55: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	556
A.191	Run 56: Top View Temperature Profile at 0.25 Pore Volumes Injected	557
A.192	Run 56: Top View Temperature Profile at 0.50 Pore Volumes Injected	558
A.193	Run 56: Top View Temperature Profile at 0.75 Pore Volumes Injected	559
A.194	Run 56: Top View Temperature Profile at 1.00 Pore Volumes Injected	560
A.195	Run 56: Top View Temperature Profile at 1.25 Pore Volumes Injected	561
A.196	Run 56: Top View Temperature Profile at 1.50 Pore Volumes Injected	562
A.197	Run 56: Top View Temperature Profile at 1.75 Pore Volumes Injected	563
A.198	Run 56: Top View Temperature Profile at 2.00 Pore Volumes Injected	564
A.199	Run 56: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	565
A.200	Run 56: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	566

A.201	Run 56: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	567
A.202	Run 56: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	568
A.203	Run 58: Top View Temperature Profile at 0.25 Pore Volumes Injected	569
A.204	Run 58: Top View Temperature Profile at 0.50 Pore Volumes Injected	570
A.205	Run 58: Top View Temperature Profile at 0.75 Pore Volumes Injected	571
A.206	Run 58: Top View Temperature Profile at 1.00 Pore Volumes Injected	572
A.207	Run 58: Top View Temperature Profile at 1.25 Pore Volumes Injected	573
A.208	Run 58: Top View Temperature Profile at 1.50 Pore Volumes Injected	574
A.209	Run 58: Top View Temperature Profile at 1.75 Pore Volumes Injected	575
A.210	Run 58: Top View Temperature Profile at 2.00 Pore Volumes Injected	576
A.211	Run 58: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	577
A.212	Run 58: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	578
A.213	Run 58: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	579
A.214	Run 58: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	580
A.215	Run 59: Top View Temperature Profile at 0.25 Pore Volumes Injected	581
A.216	Run 59: Top View Temperature Profile at 0.50 Pore Volumes Injected	582
A.217	Run 59: Top View Temperature Profile at 0.75 Pore Volumes Injected	583
A.218	Run 59: Top View Temperature Profile at 1.00 Pore Volumes Injected	584

A.219	Run 59: Top View Temperature Profile at 1.25 Pore Volumes Injected	585
A.220	Run 59: Top View Temperature Profile at 1.50 Pore Volumes Injected	586
A.221	Run 59: Top View Temperature Profile at 1.75 Pore Volumes Injected	587
A.222	Run 59: Top View Temperature Profile at 2.00 Pore Volumes Injected	588
A.223	Run 59: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	589
A.224	Run 59: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	590
A.225	Run 59: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	591
A.226	Run 59: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	592
A.227	Run 62: Top View Temperature Profile at 0.25 Pore Volumes Injected	593
A.228	Run 62: Top View Temperature Profile at 0.50 Pore Volumes Injected	594
A.229	Run 62: Top View Temperature Profile at 0.75 Pore Volumes Injected	595
A.230	Run 62: Top View Temperature Profile at 1.00 Pore Volumes Injected	596
A.231	Run 62: Top View Temperature Profile at 1.25 Pore Volumes Injected	597
A.232	Run 62: Top View Temperature Profile at 1.50 Pore Volumes Injected	598
A.233	Run 62: Top View Temperature Profile at 1.75 Pore Volumes Injected	599
A.234	Run 62: Top View Temperature Profile at 2.00 Pore Volumes Injected	600
A.235	Run 62: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	601
A.236	Run 62: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	602

A.237	Run 62: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	603
A.238	Run 62: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	604
A.239	Run 63: Top View Temperature Profile at 0.25 Pore Volumes Injected	605
A.240	Run 63: Top View Temperature Profile at 0.50 Pore Volumes Injected	606
A.241	Run 63: Top View Temperature Profile at 0.75 Pore Volumes Injected	607
A.242	Run 63: Top View Temperature Profile at 1.00 Pore Volumes Injected	608
A.243	Run 63: Top View Temperature Profile at 1.25 Pore Volumes Injected	609
A.244	Run 63: Top View Temperature Profile at 1.50 Pore Volumes Injected	610
A.245	Run 63: Top View Temperature Profile at 1.75 Pore Volumes Injected	611
A.246	Run 63: Top View Temperature Profile at 2.00 Pore Volumes Injected	612
A.247	Run 63: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	613
A.248	Run 63: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	614
A.249	Run 63: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	615
A.250	Run 63: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	616
A.251	Run 64: Top View Temperature Profile at 0.25 Pore Volumes Injected	617
A.252	Run 64: Top View Temperature Profile at 0.50 Pore Volumes Injected	618
A.253	Run 64: Top View Temperature Profile at 0.75 Pore Volumes Injected	619
A.254	Run 64: Top View Temperature Profile at 1.00 Pore Volumes Injected	620

A.255	Run 64: Top View Temperature Profile at 1.25 Pore Volumes Injected	621
A.256	Run 64: Top View Temperature Profile at 1.50 Pore Volumes Injected	622
A.257	Run 64: Top View Temperature Profile at 1.75 Pore Volumes Injected	623
A.258	Run 64: Top View Temperature Profile at 2.00 Pore Volumes Injected	624
A.259	Run 64: Cross-Sectional Temperature Profile at 0.25 Pore Volumes Injected	625
A.260	Run 64: Cross-Sectional Temperature Profile at 0.50 Pore Volumes Injected	626
A.261	Run 64: Cross-Sectional Temperature Profile at 0.75 Pore Volumes Injected	627
A.262	Run 64: Cross-Sectional Temperature Profile at 1.00 Pore Volumes Injected	628
A.263	Run 47: Top View Temperature Profile at 0.25 Pore Volumes Injected	629
A.264	Run 47: Top View Temperature Profile at 0.50 Pore Volumes Injected	630
A.265	Run 47: Top View Temperature Profile at 0.75 Pore Volumes Injected	631
A.266	Run 47: Top View Temperature Profile at 1.00 Pore Volumes Injected	632
A.267	Run 47: Top View Temperature Profile at 1.50 Pore Volumes Injected	633
A.268	Run 47: Top View Temperature Profile at 2.00 Pore Volumes Injected	634
A.269	Run 47: Top View Temperature Profile at 2.50 Pore Volumes Injected	635
A.270	Run 47: Top View Temperature Profile at 3.00 Pore Volumes Injected	636
A.271	Run 47: Cross-Sectional Temperature Profile at 2.00 Pore Volumes Injected	637
A.272	Run 47: Cross-Sectional Temperature Profile at 2.50 Pore Volumes Injected	638

A.273	Run 47: Cross-Sectional Temperature Profile at 3.00 Pore Volumes Injected	639
A.274	Run 48: Top View Temperature Profile at 0.25 Pore Volumes Injected	640
A.275	Run 48: Top View Temperature Profile at 0.50 Pore Volumes Injected	641
A.276	Run 48: Top View Temperature Profile at 1.00 Pore Volumes Injected	642
A.277	Run 48: Top View Temperature Profile at 1.50 Pore Volumes Injected	643
A.278	Run 48: Top View Temperature Profile at 2.00 Pore Volumes Injected	644
A.279	Run 48: Top View Temperature Profile at 2.50 Pore Volumes Injected	645
A.280	Run 48: Top View Temperature Profile at 3.00 Pore Volumes Injected	646
A.281	Run 48: Top View Temperature Profile at 3.50 Pore Volumes Injected	647
A.282	Run 48: Top View Temperature Profile at 2.00 Pore Volumes Injected	648
A.283	Run 48: Cross-Sectional Temperature Profile at 2.50 Pore Volumes Injected	649
A.284	Run 40: Cross-Sectional Temperature Profile at 3.00 Pore Volumes Injected	650
A.285	Run 40: Cross-Sectional Temperature Profile at 3.50 Pore Volumes Injected	651
A.286	Run 26: Top View Temperature Profile at 0.25 Pore Volumes Injected	652
A.287	Run 26: Top View Temperature Profile at 0.50 Pore Volumes Injected	653
A.288	Run 26: Top View Temperature Profile at 0.75 Pore Volumes Injected	654
A.289	Run 26: Top View Temperature Profile at 1.00 Pore Volumes Injected	655
A.290	Run 26: Top View Temperature Profile at 1.25 Pore Volumes Injected	656

A.291	Run 26: Top View Temperature Profile at 1.50 Pore Volumes Injected	657
-------	---	-----

A.292	Run 26: Top View Temperature Profile at 1.75 Pore Volumes Injected	658
-------	---	-----

Figures - Appendix C

1C.	A Plot of Refractive Index versus %NaCl	675
-----	---	-----

2C.	A Schematic of the Metrabyte Data Acquisition Unit	680
-----	--	-----

Figures - Appendix D

1D.	Cable Schematics for Macintosh Computer to Modem/Plotter	696
-----	--	-----

2D.	A Schematic of the Top View of the Aberfeldy Model Showing the Coordinate Systems Used for the DISSPLA Data Files	707
-----	--	-----

List of Plates

<u>Plates</u>	<u>Page</u>
4.1 Overall View of Low Pressure Apparatus _____	61
4.2 View of Model in Operating Position _____	62
4.3 Top View of the Scaled Physical Model _____	63
4.4 Internal View of Boiler and its Coils _____	68
4.5 Fluid Collection System _____	70

Nomenclature: Part I

a	half of the major axis of drainage ellipse, m (ft)
A_{sc}	area swept by the water oil contact
B	formation volume factor
b	half of the minor axis of drainage ellipse, m (ft)
C	specific heat, kJ/kmol·K
c	shape parameter of the water oil contact
D	lateral dimension of the reservoir block or spacing between horizontal wells
d	distance of the summit of the water crest to the top of the reservoir
ds	alternative notation for ρ_s used in Table 3.3
f_s	steam quality
g	acceleration due to gravity, m/s ² (ft/s ²)
h	enthalpy per unit mass, kJ/kg (Btu/lbm)
h	thickness of formation, m (ft)
k	permeability, m ² (darcies)
k_h	thermal conductivity, kW/m·K (Btu/hr·ft·°F)
k_r	relative permeability, dimensionless
L	length or distance, m (ft)
L_v	latent enthalpy per unit mass, kJ/kg (Btu/lbm)
m	arbitrary variable, or mass
p	pressure, kPa (psia)
$\bar{q}$	conductive heat flux, m/t ³
q	flow rate, m ³ /D (B/D)
q_H	flow rate into a horizontal well, liquid-vol unit/D
q_h	heat loss rate, mL ² /t ³
r	radius, m (ft)

r_e	drainage radius, m (ft)
r_w	effective radius of model well, m (ft)
r_w	effective wellbore radius, m (ft)
S	saturation, dimensionless
T	temperature, °C or K or °F
t	time
$\bar{u}$	volumetric flux (Darcy velocity), L/t
w	mass flow rate, m/t
x	abscissa
y	ordinate
Φ	potential function
ϕ	porosity
μ	fluid viscosity, mPa·s (cp)
θ	parameter
ρ	density, g/cc (lbm/ft ³)
ω	slit width
ψ	streamline function
Δp	pressure drop, kPa (psia)
Δr	half of horizontal well length, m (ft)

Subscripts

a	aqueous phase
c	cap or base rock
c	critical
D	dimensionless quantity
E'	of point E', Figure 2.2(c)
G'	of point G', Figure 2.2(c)

H	horizontal well
i	steam injection rate
j	phase (oil, water or steam)
m	model
o	oil
or	residual oil saturation to steam
p	prototype
R	reference variable used to obtain a dimensionless quantity
r	reservoir rock, except with k
s	steam
sat	saturation temperature or pressure
sc	calculated steam temperature
ss	superheated steam
t	total interval
V	vertical well
w	water (unless otherwise specified)
wc	irreducible water

Nomenclature: Part II

r, θ, z	cylindrical coordinates (r is positive upward)
ρ_r	reservoir rock density, Kg/m^3
ρ_o, ρ_u, ρ_g	density of Oleic, Aqueous, and Vapour phases, Kg/m^3
k	absolute permeability of porous medium, m^2
$k_{r,i}$	relative permeability of phase i , m^2 (i =Oleic, aqueous, and vapour)
ρ_{ob}	density of overburden materials, Kg/m^3
v_r, v_θ, v_z	velocities along the coordinate directions, m/s
P_o, P_u, P_g	pressures of oleic, aqueous, and vapour phases, Pa
P_{oi}	initial oleic phase pressure, Pa
C_{ij}	concentration of component j in phase i , mass fraction
S_o, S_u, S_g	saturation of oleic, aqueous, and vapour phases, fraction
S_{oi}, S_{ui}	initial saturations for oleic and aqueous phases, fraction
h_o, h_u, h_g	enthalpies of oleic, aqueous, and vapour phases, KJ/Kg
U_o, U_u, U_g	internal energies of oleic, aqueous, and vapour phases, KJ/Kg
U_r	internal energy of reservoir rock, KJ/Kg
K_{kr}	thermal conductivity of reservoir rock, $KW/m^\circ K$
K_{kob}	thermal conductivity of overburden rock, $KW/m^\circ K$
T	reservoir temperature, $^\circ K$
T_{ob}	overburden temperature, $^\circ K$
T_i	initial reservoir temperature, $^\circ K$
A^*	area for heat loss to overburden, associated with reservoir volume V_b , m^2/m^3
g	constant for acceleration due to gravity, m/s^2
q_o^*	oleic phase (injection +ve, production -ve) rate, $Kg/s.m^3$
q_u^*	aqueous phase (injection +ve, production -ve) rate, $Kg/s.m^3$
q_g^*	vapour phase (injection +ve, production -ve) rate, $Kg/s.m^3$
q_h^*	heat (injection +ve, production -ve) rate, $KJ/s.m^3$
q_i^*	heat loss rate, $KJ/s.m^3$
α_r	reservoir rock thermal diffusivity ($\alpha_r = K_{kr}/\rho_r C_r$), m^2/s
C_r	specific heat of reservoir rock, $KJ/Kg.^\circ K$
α_{ob}	overburden thermal diffusivity, m^2/s
C_{ob}	specific heat of overburden rock, $KJ/Kg.^\circ K$
ϕ	porosity, fraction
r^*	radius of the horizontal well, m
μ_o, μ_u, μ_g	viscosity of Oleic, Aqueous, and Vapour phases, $mPa \cdot s$
v	velocity of the fluids flowing inside the horizontal well, m/s
v_{out}	velocity of the fluids at the outler of the horizontal well, m/s
α^*	portion of the periphery of the horizontal well open to flow, fraction
P_p	pressure differential across the horizontal well, Pa
J	mechanical equivalence of heat energy
W	work energy done by/or the fluids flowing inside the well, KJ/s
W_{ij}	mass injection rate of component j in phase i , fraction
T^*	temperature differential between the horizontal well and the initial reservoir temperature, $^\circ K$



Chapter 1

Introduction

At the present time steam injection processes account for the recovery of over one million barrels of heavy oil each day. The two major types of steam injection techniques are cyclic steam stimulation and steamflooding. To-date, cyclic steaming is the only proven commercial heavy oil recovery scheme to be successful in recovering heavy oil from the Cold Lake oil sands formations. Steamflooding has been quite suitable for some California heavy oil reservoirs such as San Ardo, Kern River and Midway Sunset fields. Recently the steamflood process has been implemented in some Saskatchewan fields such as the Aberfeldy.

Many heavy oil reservoirs in Alberta and Saskatchewan contain a characteristic bottom water layer which creates a serious field problem when a steamflood process is implemented. The presence of the underlying water zone causes a large amount of the injected steam to be diverted away from the target oil zone and into the bottom water layer. This results in the steamflood process having a low thermal efficiency and therefore the steamflood is uneconomical in these types of reservoirs.

The main focus of this research was to incorporate solvent injection with a steamflood process in an attempt to improve oil recovery from thin heavy oil formations with underlying water zones. The purpose of the solvent slug injection prior to steamflooding was to create highly conductive flow channels into the oil zone for the steam to penetrate. It was thought that the solvent channels formed in the oil region would aid in partially diverting the steam away from the detrimental bottom water zone, resulting in a greater volume of oil being heated, mobilized and consequently produced. The objective of the solvent-steamflood method was to guide the steam into the upper portion (oil layer) of the bottom water formation and keep the steam there as long as possible.

Other recovery schemes were investigated which also attempted to divert the steam away from the underlying water and into the oil region. The alternate methods considered were gas injection prior to a steamflood or solvent-steamflood and prior to steamflooding a limited barrier was formed at the oil/water contact of the formation which extended radially outward from the injection well.

Chapter 2

Literature Review

This chapter provides a review of literature describing past scaled model studies which were used for investigating steam injection techniques, miscible (solvent) displacements, recovery processes combining solvent with steam into one process in an attempt to improve the overall oil recovery and a study of horizontal well technology.

The initial portion of the review highlights major high and low pressure model investigations as well as studies which involved deriving the scaling criteria used to design the models. The section also reviews studies which investigated oil recovery by steam injection into oil reservoirs containing bottom water.

Next, the literature survey deals with miscible displacement research and studies involving the incorporation of miscible (solvent) displacement with a steam injection process. Important mechanisms of miscible displacement (dispersion and diffusion) and some non-thermal miscible displacement studies are described. Also included are research studies which attempted to develop scaling criteria which would adequately represent a process combining solvent and steam injection. Experiments which examined the implementation of solvent injection with thermal recovery techniques such as hot waterflooding and steam injection are discussed, and research investigations involving asphaltene flocculation, often caused by solvents, are reported.

The final section is a review of horizontal well technology for producing heavy oils and oil sands. The review includes a discussion of the reservoir engineering aspects of horizontal wells, particularly the productivity of horizontal wells in homogeneous and isotropic reservoirs as well as the influence of anisotropy on productivity. In addition, water coning is examined because horizontal wells provide a new approach to reducing and sometimes, eliminating this problem, which is commonly encountered in conventional vertical wells. Horizontal well flow behaviour is analyzed for early and late time flow

geometry. For heavy oil recovery, the steam assisted gravity drainage process employed with horizontal wells seems to give substantially higher recovery than that obtained for vertical wells. Consequently, the concept of gravity drainage is also discussed. In mature steam drives, there is significant steam override. Horizontal well applications reduce the gravity segregation effects and hence, permit oil production from bottom layers. The final topic of this paper deals with the optimum well pattern configurations based on numerical simulation studies.

Scaled Model Studies of Steam Injection Processes

Several in-depth reviews detailing the current state of steamflood (or steam drive) technology have been presented in the literature ^{1,2}. Farouq Ali ³ gives a comprehensive description of the theories that have been proposed to explain the mechanics of steam advance in oil bearing strata.

Models for obtaining a good understanding of the physical processes involved in a steamflood operation have also been extensively employed as predictive tools designing the best recovery program for a particular reservoir. Most of these models were unscaled. Only in a few instances scaled models were used.

Experimental Approaches to Steam Injection

Various types of physical models have been used to examine many types of thermal recovery processes. Some models have been used to study various relevant operating parameters such as steam injection rate and pressure, steam quality, pattern size and type, and reservoir thickness. Other laboratory models have been used to examine steam injection strategies in which recovery was from reservoirs with specific characteristics such as gas caps, high oil viscosity, bottom water, shale stringers, or a high waterflood residual oil saturation.

There are three basic types of physical models which can represent various types of prototype reservoirs; these are: unscaled, partially scaled and scaled.

Unscaled models, sometimes called "elemental models", involve neglecting scaling criteria completely and focussing on a certain aspect of the process in order to try to obtain the qualitative nature of a particular recovery mechanism such as steam distillation. The experimental conditions and materials for a unscaled model are chosen to represent an element of the prototype reservoir under investigation. Even though the unscaled model does not provide a quantitative analysis, unscaled experiments can yield critical information about the specific processes being investigated. Unscaled models are used to obtain a better understanding of the fluid-rock interactions occurring in the reservoir at various conditions .

Willman, Valleroy, Runberg, Cornelius and Powers ⁴ were the first investigators to carry out unscaled laboratory studies on steam injection. Their research produced valuable data on the various mechanisms that exist during a steamflooding operation. Linear cores saturated with refined oils and crudes, which had different viscosities and steam distillation properties, were used in the experiments. Results of the study produced steam injection oil recoveries one hundred percent better than previously recorded waterflood oil recoveries. Thermal expansion of the oil, viscosity reduction, and steam distillation were the specific mechanisms responsible for the improved recovery by steam injection. Marx and Langenheim ⁵ presented the first equations to predict the performance of a steamflood.

Baker ⁶ investigated heat flow during steam injection and found that heat losses from the reservoir were a function of time, reservoir thickness and thermal diffusivity. He also concluded that gravity override during steam injection was a common phenomenon. Oil was not used in these experiments.

Flock and Lee ⁷ examined the use of steam injection to displace a medium gravity crude from an unconsolidated sand pack. Results of this investigation were similar to those obtained by Baker ⁶. Flock and Lee ⁷ concluded that steam injection into a medium gravity crude oil formation, that had previously been waterflooded, could be a viable tertiary recovery technique.

Scaled and partially scaled model studies have been performed to determine the effect of changes in various operational parameters such as completion intervals, flood pattern and size, steam quality, steam additives, slug size, injection rate, production pressure and reservoir heterogeneities.

An extensive review of the methods used in scaling steam injection processes was given by Farouq Ali and Redford ⁸ in which they used the Principle of Similarity as the basis of design for a scaled physical model. The Principle of Similarity is based on equivalence of ratios of forces, velocities, dimensions, temperature differences, and concentration differences which exist in the model and the prototype reservoir.

High Pressure and Low Pressure Scaled Models

When performing scaled model studies of thermal recovery processes, two types of scaling methods can be utilized. One can design either a high pressure model or a low pressure model, where each type has its advantages and disadvantages.

Often high pressure models use the same fluids as the prototype and therefore are thought to provide an improved scaling of the rock-fluid interactions such as permeability, relative permeability, and capillary pressure alterations. The low pressure model according to Stegemeier, Laumbach and Volek ⁹ better conforms to the Clausius-Clapeyron relation due to the subatmospheric pressures and low temperatures that can be achieved with a vacuum model. The improved matching of the Clausius-Clapeyron relationship results in improved modeling of the temperature distribution in the prototype. The temperature distribution can be related to the viscosity distribution, internal energy distribution, and the steam zone pressure gradient, which are all significant features of a thermal recovery process. In practical terms, the vacuum model is more economical, safer and can turn out results much faster than a high pressure model.

Compressibility cannot be accounted for by either one of the models. Kimber, Puttagunta and Farouq Ali ¹⁰ noted that reservoir fluids and porous media could only be

used in a high pressure model if the geometric similarity could be distorted in the vertical dimension, which would affect other scaling parameters.

Prats ¹¹ stated that relative permeability could not be incorporated into the scaling of a vacuum model. This was also found to be true for a high pressure model, but to a lesser degree, especially if the model scaling parameters permit the use of the reservoir rock and fluids.

The use of both high and low pressure scaled models provides a valuable insight into the various mechanisms that exist during the steamflood process.

Geertsma, Croes and Schwarz ¹² were the first to develop a set of dimensionless groups for scaling a displacement process in which hot water was injected in order to increase the recovery in viscous crude reservoirs. They also derived scaling groups for a solvent injection process and a conventional water drive. Loomis and Crowell ¹³, Leverett, Lewis and True ¹⁴, Rapoport ¹⁵ and Perkins and Collins ¹⁶ have performed other scaled model studies using different scaling criteria related to waterfloods.

A set of high pressure scaling criteria involving multidimensional steam injection was developed by Pujol and Boberg ¹⁷. These steam injection scaling criteria have served as a basis for other scaled model studies such as those performed by Pursley ¹⁸ and Ehrlich¹⁹.

Pursley ¹⁸ incorporated the Pujol-Boberg scaling criteria to model reservoir conditions of a Cold Lake, Alberta, reservoir using a number of three-dimensional models. Among the purposes of the scaled model study it was intended to determine whether a gas cap or bottom water zone could be utilized during a steam injection process. Pursley ¹⁸ concluded that during a steam injection process the presence of bottom water aided oil recovery due to steam override, which caused a large region of the oil to be contacted. It was also proposed that a steam drive through a bottom water zone was possible if heating close to the base of the oil could be achieved and good vertical permeability existed. However, for thicker bottom water layers bottom water had a detrimental effect, and

significantly reduced oil recovery. In other experiments, Pursley¹⁸ found that the existence of a gas cap could help oil recovery if a thin bottom water layer was separated from the oil by an impermeable layer. Pursley¹⁸ also performed experiments studying pattern size, steam bank size and additives to steam.

Experiments performed by Ehrlich¹⁹ implemented a three-dimensional model which scaled a steam displacement in the Wabasca Grand Rapids 'A' sand. This model was developed according to the Pujol-Boberg scaling criteria. Ehrlich¹⁹ found that areal sweep efficiency was high due to low effective steam mobilities and vertical sweep efficiency was low as a result of steam override.

Huygen and Lowry²⁰ carried out unscaled, high pressure model experiments studying steam injection in the presence of bottom water. The unscaled model used was a three-dimensional, high pressure model which considered only heat flow in the scaling calculations. Results showed that the bottom water counteracted the overriding tendency of steam. It was also concluded that bottom water can provide the much needed steam injectivity in immobile tar sands but it could also scavenge the steam's heat from the oil, creating an inefficient recovery process in the case of a thicker bottom water region.

The first low pressure scaled model studies were performed by Stegemeier, Laumbach and Volek⁹. They noted that the low pressure model porous media had to be different from those in the prototype reservoir. The scaling criteria derived were used to develop the low pressure model used in this study.

The scaled experiments performed by Stegemeier et al.⁹ were designed to provide operational assistance for numerous steamflood field operations implemented by the Shell Oil Company. Some of these operations included Tatum, Slocum, Peace River, Coalinga, Mt. Poso, Midway Sunset and Yorba Linda, fields.

Stegemeier et al.⁹ reported vacuum model study results for both the Midway Sunset and Mt. Poso fields. Results of the Mt. Poso suggested that steam override would be a governing feature in the field. The Mt. Poso experiments enabled recommendations to

be made which made Mt. Poso a successful steamflood. The Midway Sunset experiments were directed towards comparing steamflood and steam soak results. Harmsen²¹ discussed the distinct advantages steamflooding had over cyclic steaming in specific situations.

Utilizing the scaling criteria developed by Stegemeier et al.⁹, Prats¹¹ performed numerous vacuum model experiments studying the Peace River, Alberta, oil sand formation in which a bottom water layer is present. Various operational parameters such as injection rates, completion interval, steam quality, pressure levels and heat scavenging by water injection after steam injection were investigated.

Based on the scaling criteria developed by Stegemeier et al.⁹, Doscher²² designed a low pressure model. The scaling parameters were developed from similarities in an integral form, derived from a study by Yortsos²³ as opposed to the differential form used by Stegemeier et al.⁹. The model was utilized by Doscher and Huang²⁴ to examine the steam drive performance in a heavy oil field similar to Kern River. The effect of bottom water, injection rate, steam quality, reservoir permeability and oil viscosity were studied in this investigation. It was concluded from the study that an optimum steam injection rate existed, with the performance (cumulative oil recovered) falling off above and below this injection rate. Experiments carried out by Doscher and Ghassemi²⁵ used this vacuum model to study the effect crude oil viscosity has on the efficiency of a steam injection operation.

Proctor²⁶ constructed a three-dimensional, low pressure model of the Aberfeldy formation which is a thin, heavy oil reservoir. The design of the model was based on the scaling criteria derived by Stegemeier, Laumbach and Volek⁹. From the results of steam injection experiments performed in the model Proctor²⁶ concluded that the presence of bottom water in the reservoir had an extremely detrimental effect on the thermal efficiency of a steam injection process.

Studies of Thin, Bottom Water Reservoirs

Several studies have investigated oil recovery by steam injection into oil reservoirs containing bottom water. However, none of these studies dealt with thin reservoirs containing relatively thick bottom water regions and/or a gas cap zone. For this study a "thin heavy oil reservoir" was considered to be a heavy oil formation with a thickness of less than about 20 meters (65 feet). The prototype reservoir studied in this research is the thin, Aberfeldy reservoir which does not have a gas cap and a bottom water layer only exists in parts of the field. However the versatility of the equipment used in this research allows one to create a bottom water layer and/or a gas cap in the model of the Aberfeldy reservoir.

Prats ¹¹ modelled the Peace River reservoir which is characterized by a large oil saturation (45%) in the bottom water layer. In his experiments he injected steam into the bottom water and increased pressure in the reservoir in an attempt to heat up the bottom water zone. This procedure enabled the overlying, highly viscous oil zone (65% oil saturation) to be mobilized by the heating effects of the bottom water zone. Due to the relatively high oil saturation in the bottom water zone the initial injection of steam into this zone resulted in a significant amount of oil being produced which increased the economic attractiveness of the recovery process. To further improve oil recovery, steam was injected directly into the oil zone once the oil saturation in this region was reduced to a predetermined value. The Wabasca reservoir examined by Huygen and Lowry ²⁰ and the Cold Lake reservoir studied by Pursley ¹⁸ were both characterized by a relatively thin bottom water layers. These investigations therefore do not provide a reasonable representation of Aberfeldy type thin reservoirs. Other than the study performed by Doscher and Ghassemi ²⁵ there has been little work done on steamflooding thin oil reservoirs such as the Aberfeldy.

A variety of production mechanisms are called into play during thermal stimulation of bottom water reservoirs as pointed out by Kasraie and Farouq Ali ²⁷. A study of present field and laboratory information by the authors concluded that cyclic steaming becomes uneconomical when a water zone exists that is thicker than one-fifth of the oil zone thickness. As well the presence of a gas saturation may be effective in a steamflood of a thin reservoir with bottom water if vertical permeability is high, which will promote gravity flow of the steam. In such an instance, it may be possible to spread the injected steam over the entire formation and develop a downward steam drive. This would improve the thermal efficiency of the steamflood due to less of the injected heat being scavenged by the underlying bottom water layer. It was also pointed out that many heavy oil formations in Alberta and Saskatchewan have underlying water sands. A well-known steamflood, where both bottom water and a gas cap exist is the Smackover flood ²⁷ in Arkansas, which is operated at below atmospheric pressure. It is possible that the presence of the gas cap counteracts the channelling of steam into the bottom water.

A subsequent study by Kasraie and Farouq Ali ²⁸ further discussed the application of thermal recovery techniques to "marginal" heavy oil reservoirs. Such reservoirs are defined to have one or more of the following characteristics: thin formation (less than 6 metres), bottom water, gas cap or very high oil viscosity (over 10 Pa.s). Thermal recovery applications under such conditions depend strongly on the extent of bottom water, oil viscosity, vertical permeability, oil saturation and fluid injection rate. Vertical permeability was found to be an important factor in marginal reservoirs, which are characterized by bottom water, a gas cap, thin pay and extra-heavy oil. The vertical permeability is of considerable importance in these types of formations since even a limited barrier between the oil and water zones would drastically reduce the tendency of the steam to channel down into the water layer. Therefore any shale breaks, silt zones or other heterogeneities at the base of the oil sand would serve to improve the oil recovery performance. Also the

implementation of high temperature polymers, foams or additives, such as solvents, may also help to divert the steam away from the bottom water.

Incorporation of Solvent with Steam Injection Processes

Dispersion and Diffusion of Solvents in a Porous Medium

A thorough review of diffusion and dispersion in porous media was presented by Perkins and Johnston ²⁹. Dispersion was defined as the mixing of solvent and oil in a porous medium caused by uneven fluid flow or concentration gradients resulting from fluid flow. It was also noted that dispersion could occur in the longitudinal direction (direction of gross fluid flow) or transversely (perpendicular to gross fluid flow direction). Diffusion was described as the mixing of two miscible fluids arising from the random motion of the molecules in each fluid.

Along with dispersion and diffusion, imbibition plays an important role in oil recovery during a solvent and/or steam injection process. Graham and Richardson ³⁰ performed theoretical and experimental studies of water imbibition in which they stated that an understanding of the role of imbibition in implementing the recovery of oil is deemed essential to proper control of reservoirs to achieve maximum oil recovery. In the study, imbibition was defined as the spontaneous taking up of a liquid by a porous solid. The spontaneous process of imbibition occurs when the fluid-filled solid is immersed or brought in contact with another fluid which preferentially wets the solid. In the process of wetting and flowing into the solid, the imbibing fluid displaces the non-wetting resident fluid.

Non-Thermal Miscible Displacement Processes

A vast amount of literature exists on miscible displacement. In the following, only the papers relevant to the present research will be reviewed. As reported by Holm ³¹ miscible displacement of oil is defined as the displacement of crude oil from pore space in a

rock using a solvent action that prevents the formation of interfaces between the driven and the driving fluids.

Stalkup ³² performed work studying oil displacement by solvent at high water saturations. He concluded that in a miscible displacement in the presence of a high water saturation, some of the oil is blocked by water so that it is bypassed by the solvent front and is therefore not recovered. For the case of a miscible displacement in the presence of a high water saturation the dominant mechanisms responsible for oil recovery are miscible flushing by solvent of the portion of the hydrocarbon pore volume that contains mobile oil and molecular diffusion of the region of the hydrocarbon pore volume that is stagnant. In general, the higher the water saturation, the greater the longitudinal dispersion and the more oil is bypassed by the injected solvent.

In miscible slug flooding, the formation of mixing zones occurs between the reservoir oil and the solvent bank as well as the solvent bank and the scavenging fluid. The dimensionally scaled model test results of Craig ³³ have shown that there is a tendency for channelling to occur due to gravity segregation of the oil, solvent, and scavenging fluid, resulting in more bypassing of in-place oil. He showed that these effects are reduced when the process is carried out in a permeable, steeply dipping reservoir. It was also noted that in order to maintain miscibility in field miscible floods the solvent slug volume should range from two to ten percent of the total in-place hydrocarbon pore volume of the reservoir.

Due to the high costs of solvents, the amount of solvent to be injected is a critical factor in the success of a miscible displacement process. If the solvent slug used is larger than required, then the solvent cost will be increased without a compensating rise in the oil recovery, and if too small a slug is employed then a large portion of recoverable oil is left behind in the reservoir. This was the basis for a study conducted by Baker ³⁴, which predicted solvent slug requirements in an idealized linear system where gravity, mobility ratio and areal sweep effects were unimportant, but longitudinal dispersion (mixing at the leading and trailing edges of the bank) and capacitance effects were significant. Capacitance

is defined as the growth of a mixing zone caused by the trapping of oil and solvent in heterogeneities in the reservoir. The fluids were trapped by the shielding effects of the water films in the rock heterogeneities. From the study Baker ³⁴ found that slug size was affected by several variables, including reservoir geometry, interwell spacing, gravity effects and mobility ratio. He also determined that slug degradation was caused by mixing (by dispersion) of the solvent with oil at the leading edge of the solvent bank and with the drive fluid at the trailing edge.

Similarly to numerous other investigators, Rodriguez ³⁵ also found that at an unfavourable mobility ratio, viscous fingering is the controlling factor in a miscible displacement. Totonji ³⁶, conducting miscible displacements in consolidated and unconsolidated sandpacks, found that the absolute viscosities of the liquids involved had little effect on the process if conducted at a constant unfavourable viscosity ratio.

Experimental results of a number of investigators ^{37,38,39} have shown that a gradual change from a more to a less viscous injected fluid can mitigate the detrimental effects of viscous fingering on areal sweep efficiency in reservoir displacement processes. Research performed by Claridge ⁴⁰ indicated that it is unlikely that viscous fingering can be completely prevented during unstable miscible displacement in oil reservoirs but the use of a graded bank often may result in improvements in both overall oil recovery and/or economic viability.

The relative economic attractiveness of miscible slug floods depends upon both the cost of solvent and oil recovery performance expected of competing oil recovery techniques. To-date about forty percent of all miscible slug field projects operated under favourable conditions have yielded either good or encouraging oil recovery efficiencies. In recent years, considerable interest has been shown in the use of solvents as a means of recovering oil left in a reservoir at the end of secondary recovery operations.

Solvent Scaling Criteria

A non-rigorous set of criteria, which treated a steam plus additive process as a steam recovery process plus a miscible drive, was derived by Kennedy and Crawford ⁴¹. The study concluded that scaling of the combined steam and solvent processes could not be achieved as the scaling requirements for the flow rate in the steam recovery process contradicted the scaling requirements for the flow rate in the miscible drive process. As well Pursley ¹⁸ attempted a partially scaled model investigation of the process in which solvent was simply added to his steamflood model.

Pozzi and Blackwell ⁴² studied the scaling of isothermal miscible displacements. They determined that under specific conditions, the requirements of geometric similarity and gravitational scaling can be relaxed to allow scaling of miscible displacement, whether transverse mixing is by molecular diffusion or by convective dispersion.

Kimber, Puttagunta and Farouq Ali ¹⁰ presented new scaling criteria for steam and steam additive recovery experiments. From this study, the authors derived a complete set of similarity groups required to scale the steam or steam plus an additive (eg. solvent) process as defined by governing differential equations, constraints, constitutive relationships and initial and boundary conditions which had been developed. Five sets of scaling criteria, each representing a subset of the more complete set of scaling requirements, were developed by relaxing the scaling of various phenomena. The best approach to use would depend on the particular process to be scaled. The approach chosen should correctly scale the major mechanisms of the process and not cause minor mechanisms in the process to have significant effects on the response of the experimental model.

Incorporation of Solvent Injection into Thermal Recovery Methods

Alikhan and Farouq Ali ⁴³ investigated a recovery process, which incorporated miscible displacement with hot waterflooding. The study considered oil recovery from a formation containing either a residual oil saturation or a connate water saturation, sealed

above and below by heat-conducting strata. The recovery process involved introducing a small slug of a light hydrocarbon prior to the injection of one-half pore volume of hot water followed by a conventional cold waterflood. Results indicated that pre-injection of the light hydrocarbon slug preceding the waterflood led to a greater oil recovery than that obtained for a conventional waterflood. Alikhan and Farouq Ali ⁴³ also found that the overall oil recovery by this technique was dependent on oil viscosity, light hydrocarbon slug viscosity and the injection rate. The process was also found to be more effective when the reservoir had been previously waterflooded as opposed to a connate water saturation initially existing in the formation. Solvent recovery was found to be better if a higher initial oil saturation existed.

In studying the application of solvent slugs in thermal operations Farouq Ali ⁴⁴ investigated the change in phase behaviour characteristics due to an increase in temperature of the fluids involved in a solvent/steam recovery process. He concluded that at elevated temperatures the overall phase behaviour of a typical alcohol-brine system would shift in such a direction as to make displacement of oil by alcohol more efficient. This could be achieved by injecting a small alcohol or solvent slug ahead of a steamflood.

A study by Pirela and Farouq Ali ⁴⁵ investigated the ternary phase behaviour of solvent-oil-water systems at high temperatures. An increase in the temperature of the system resulted in an increase in the miscibility of the system, which was found to be advantageous from the standpoint of oil recovery.

The chief objective of a study performed by Totonji and Farouq Ali ⁴⁶ was to exercise control on the system phase behaviour through the use of mixtures of two alcohols exhibiting opposite phase behaviour characteristics in the alcohol-hydrocarbon-water system involved. Such systems were employed in displacements in porous media to ascertain the effectiveness of the systems and it was found that the oil recovery could be improved using these systems.

Experiments conducted by Ozen and Farouq Ali ⁴⁷ using linear, consolidated cores under isothermal conditions revealed that a steam drive could be an effective technique for recovering the residual oil from a waterflood. They also found that the introduction of a small slug of light hydrocarbon (naphtha) preceding steam injection improved the overall oil recovery.

Hernandez and Farouq Ali ⁴⁸ used a one-dimensional model (linear) to examine the use of solvent injection to form a channel through the tar sand, connecting the injection and production wells prior to the injection of steam into the tar sand. Results of the study indicated that the injection of a solvent slug preceding steam injection created improved steam injectivity into the oil zone and a higher overall recovery. It was also noted that the smaller solvent slugs aided forming a channel into the tar sand for the steam, whereas the larger solvent slugs created a permeability block which inhibited steam flow.

Snyder and Farouq Ali ⁴⁹ proposed the use of solvents as a means of developing flow channels in the tight tar sand to provide the initial flow paths for the injected steam. In this study the authors investigated the recovery efficiency of naphtha injection into a two-dimensional homogeneous tar sand pack at various injection rates, the effectiveness of gravity segregation and conductive heating in tar packs with a highly permeable channel joining the inlet to the outlet. A permeable layer existed near the base of the pack. Information obtained from the study indicated that during steam injection the steam action is concentrated around the inlet and did not directly contact the majority of the pack and therefore naphtha injection prior to steam injection in a homogeneous pack was highly effective in opening a steam flow path. Once created, it allowed the steam to become more concentrated towards the production outlet resulting in improved overall oil recovery. It was also noted that total oil recovery improved as solvent residence time increased and as displacement rate in the recovery process decreased.

Farouq Ali and Abad ⁵⁰ studied the use of solvents in combination with steam using a three-dimensional elemental model. These authors found that the type of solvent, the

volume of solvent slug, and the placement of the solvent in the reservoir determined the extent of the bitumen recovery. They found that smaller solvent slugs were more effective than larger slugs and that there existed an optimum combination of solvent and steam slug sizes which optimized the overall bitumen recovery.

A study performed by Farouq Ali, Look Yee, Cordero and Figueroa ⁵¹ reported that implementing a thermal recovery method requires the creation of flow paths for the initial injection of a hot fluid. Comparisons of the base steamfloods and the solvent-steamfloods performed during the investigation show that the solvent-steamfloods did improve oil recovery. It was also determined in the study that the injected solvent spread over a large area by viscous fingering if the injection rate was very high, while if the rate was low the solvent essentially diffused into the bitumen and was largely confined to the immediate vicinity of the injection well.

In an economic evaluation of solvent/steam stimulation Doscher, Ershaghi, Herzberg and Gourene ⁵² suggested that by reducing the viscosity of crude oil before contact with steam by use of a solvent, the overall steam requirement to achieve the same recovery without solvent might be reduced. The success of this type of proposal was found to depend on whether it was possible to obtain a marginally greater reduction in viscosity by the mixing of solvent and crude oil as compared to using an economically equivalent amount of steam. Doscher et al. ⁵² also stated that for reservoirs where steam soaking operations were not attractive due to extreme heat losses, the utilization of a solvent/steam process needed to be investigated more carefully. The authors also suggested that solvent should be used in combination with steam to achieve specific advantages in a steam drive operation such as establishing or increasing conductivity between injection and production wells or increasing sweep efficiency.

Redford and McKay ⁵³ found that the use of a solvent in a steam process may reduce the residual saturation in the water-swept areas of the reservoir and thus improve the overall oil recovery. For solvents which are mixed hydrocarbons the more volatile additive

(light ends) may act as a drive agent while the less volatile (heavier ends) one may act as a viscosity-reducing agent during the pressure depletion portion of the cycle which further improved recovery.

Redford ⁵⁴ reported that the use of naphtha in combination with steam improved oil recovery by reducing bitumen viscosity and thereby improving recovery in the water-swept portions of the reservoir, thus making more efficient use of the drive energy provided by the steam.

A comprehensive study carried out by Alikhan and Farouq Ali ⁴³ investigated a combination of three different processes for the recovery of light and relatively viscous oils, using two approaches: injection of a slug of a light hydrocarbon miscible with the viscous oil, followed by the injection of hot water in one series of experiments, and a steam slug in another series, each of which was then driven by water. Essentially the mechanism of the process was a combination of miscible displacement, hot waterflooding and steamflooding. The process was designed for a high thermal efficiency utilizing the maximum amount of heat injected. Conclusions drawn from the investigation suggested that the solvent slug injected prior to the hot water or steam slug in a sandpack improved oil recovery as compared to a straight hot water or steam slug run. The solvent, in view of the prevailing adverse mobility ratio, mixed with the original in-place oil, and helped to lower the oil viscosity. The viscosity was further reduced by the heat from the injected hot water or steam slug, which led to an improvement in the mobility ratio and hence an improvement in the displacement efficiency. A large proportion of the light hydrocarbon slug was recovered by the steam distillation effect. It was also determined that the recovery ratio was higher and the steam residual oil saturation was lower when a steam slug was employed rather than a hot water slug. Recovery ratio was defined as the total hydrocarbon produced divided by the amount of hydrocarbon slug injected. The recovery ratio gave a basic indication of the rise in oil recovery due to the injection of the additional hydrocarbon in conjunction with the hot water.

In a recent study, Yamazaki, Matsuzawa, Abdeldarim and Ono ⁵⁵ reported that when solvent was injected with steam, bitumen recovery increased and this increase was directly proportional to the rate at which solvent was injected. Yamazaki et al. ⁵⁵ examined the use of benzene, cyclohexane and halide with steam injection and found that benzene and cyclohexane had nearly the same effect on the bitumen recovery enhancement, whereas halide appeared to be the least effective solvent.

Asphaltene Flocculation

In some instances, when bitumen is mixed with certain light, saturated hydrocarbons such as paraffinic solvents, hard friable materials called asphaltenes, may be precipitated. Asphaltene precipitation can create serious problems in the reservoir, such as constriction of fluid flow passages which results in a reduction in the formation permeability. An investigation by Knobloch, Farouq Ali and Treviño Diaz ⁵⁶ found that the asphaltenes that precipitate out are not single molecules, but clusters of molecules often coated with paraffin and resin molecules strongly bonded to the exterior of the clusters. A conclusion of the study was that asphaltene precipitation increased with an increase in solvent concentration.

A study by Snyder and Farouq Ali ⁴⁹ stated that naphtha injection may cause formation plugging by asphaltene flocculation but plugging was found to occur only when large volumes of naphtha were injected. The injection of a small amount of naphtha during a slug process would not initiate asphaltene flocculation. In the present research asphaltene precipitation was not considered to be a significant factor.

Horizontal Well Study

In recent years, interest in horizontal wells has been rekindled (see Table 2.1). Horizontal wells have been proposed for conventional recovery for tight reservoirs where production from horizontal wells exceeds that of vertical wells due to their greater reservoir contact. They are particularly effective when vertical fractures are present, in thin pay sections where water or gas coning are problems and in soft formations such as chalk

Table 2.1: List of Horizontal Well Projects for Heavy Oil Recovery

<u>Year</u>	<u>Field</u>	<u>Company</u>	<u>Process</u>	<u>Comments</u>
1937	Yarega, USSR		Steam	First horizontal well. Mine assisted steam. (Same horizontal well was used for injection and production)
1978/83/89	Rospo Mare, Italy	Elf Aquit. (& Institut Français du Pétrole in 1978/83)	Primary	Offshore in Italy.
1979	Fort McMurray, Alberta	Texaco	Steam	Wells drilled from a single drill pad using a slant rig. (Same horizontal well was used for injection and production)
1979/89	Cold Lake, Alberta	Esso Resources Canada Ltd.	Steam	Steam assisted gravity drainage process. (Horizontal producer)
1984	Cold Lake, Alberta	Esso Resources Canada Ltd.	Steam	Longest recorded horizontal well. Cyclic steam process. (Horizontal producer)
1987	Fort McMurray, Alberta	AOSTRA	Steam	Underground Test Facility (UTF). Steam assisted gravity drainage. (Two separate horizontal wells for injection and production)
1987/89	North Tangleflags, Saskatchewan	Sceptre Resources and Murphy Oil	Steam	Thermal EOR in gas/cap bottom water area. (Horizontal producer)
1988	Kern River, California	Dietrich Corp.	Steam	Steam inj./oil recovery lateral holes drilled radially from a central shaft parallel to and a few feet above the base of the heavy oil column. (Horizontal injector)
1988	Medicine Hat, Alberta	Alberta Energy Co. (AEC)	Primary	14° API oil.
1988	Pelican Lake, Alberta	Gulf	Steam	14° API oil.
1988/89	Pelican Lake, Alberta	CS Res.	Steam	Long radius well.
1988/89	Winter, Saskatchewan	CS Res.	Primary	Long radius well.
1989	Suffield, Alberta	AEC	Primary	Water coning inherent.
1989	Winter, Saskatchewan	Saskoil	Primary	Field was not previously waterflooded
1989	Plover Lake	Saskoil	Primary	Horizontal steam producer, vertical injector proposed
1989	Provost, Alberta	Pan Candian Petroleum	Primary	N/C
1989	Provost, Alberta	Renaissance Energy	Primary	N/C

which are liable to collapse. It is also felt that horizontal wells have great potential in the recovery of bitumen and heavy oil in Alberta and Saskatchewan. In view of the low injectivity of steam in the oil sands, satisfactory steam injection rates are only feasible at parting pressures. However, while high pressure steam injection is acceptable for a cyclic steam stimulation process, it may be detrimental for a subsequent steamflood. Horizontal wells offer a non-fracture alternative to the steam fracturing technology.

Theoretical and laboratory studies as well as reported field successes indicate that there are situations in which horizontal wells will likely be more effective than vertical ones. The main advantage of horizontal wells is that they contact a much greater portion of the reservoir and hence, they provide substantially higher production rates, 2 to 5 times greater (Joshi, 1986⁸⁸), than vertical wells. Horizontal wells operate with lower local fluid velocities in the reservoir while still providing adequate productivity due to the vast area which is exposed to the reservoir. This results in less sand transport into the well and reduced coning of gas or water when a gas cap or bottom water is present, respectively.

The negative aspects of horizontal wells include high drilling and completion costs, 1.5 to 2 times greater (Joshi, 1986⁸⁹) than conventional vertical wells, and their inability to produce zones separated by impermeable layers via a single wellbore. In addition, they are ineffective in thick (150 to 180 m) reservoirs with low vertical permeability (Joshi, 1986⁸⁸).

The Productivity of Horizontal Wells

Homogeneous and Isotropic Reservoirs

One of the main advantages of horizontal wells is that their productivity is greater than conventional vertical wells. The productivity of a conventional well is a function of its transmissibility (kh) which is in turn dependent on the permeability and thickness of the formation. Thus, low productivities result from either low permeability or low values of formation thickness or both. Horizontal wells can compensate for these problems because

their lengths, L , are determined by the engineer rather than by nature; the kL product in horizontal wells play a parallel role to that of the kh product in conventional wells. In fact, in heterogeneous reservoirs, the chances of penetrating a favourable geological structure increases with the distance drilled through the formation. The optimum case, encountering vertical fractures, is more likely to be met by a horizontal well rather than by a vertical one.

Giger et. al.⁷² defined the productivity index of horizontal wells as:

$$PI_H = \frac{2\pi kL}{\mu} \times \frac{1}{\frac{L}{h} \ln \left[\frac{1 + \sqrt{1 - \left(\frac{L}{2r_{eH}} \right)^2}}{\frac{L}{2r_{eH}}} \right] + \ln \left(\frac{h}{2\pi r_{wH}} \right)} \quad (2.1)$$

In comparison, the productivity index for vertical wells is simply

$$PI_V = \frac{2\pi kL}{\mu} \times \frac{1}{\ln \left(\frac{r_{eV}}{r_{wV}} \right)} \quad (2.2)$$

By taking the ratio of Equation (2.1) to (2.2), PI_H / PI_V reduces to

$$\frac{PI_H}{PI_V} = \frac{\ln \left(\frac{r_{eV}}{r_{wV}} \right)}{\ln \left[\frac{1 + \sqrt{1 - \left(\frac{L}{2r_{eH}} \right)^2}}{\frac{L}{2r_{eH}}} \right] + \frac{h}{L} \ln \left(\frac{h}{2\pi r_{wH}} \right)} \quad (2.3)$$

Equations (2.1), (2.2) and (2.3) are given for use with SI units.

The Influence of Anisotropy

In many reservoirs, the vertical permeability is less than the horizontal permeability. A decrease in vertical permeability can be detrimental for a horizontal well because it will result in an increase in the vertical flow resistance and a decrease in oil production rates. Conversely, if the vertical permeability is greater than the horizontal permeability, then

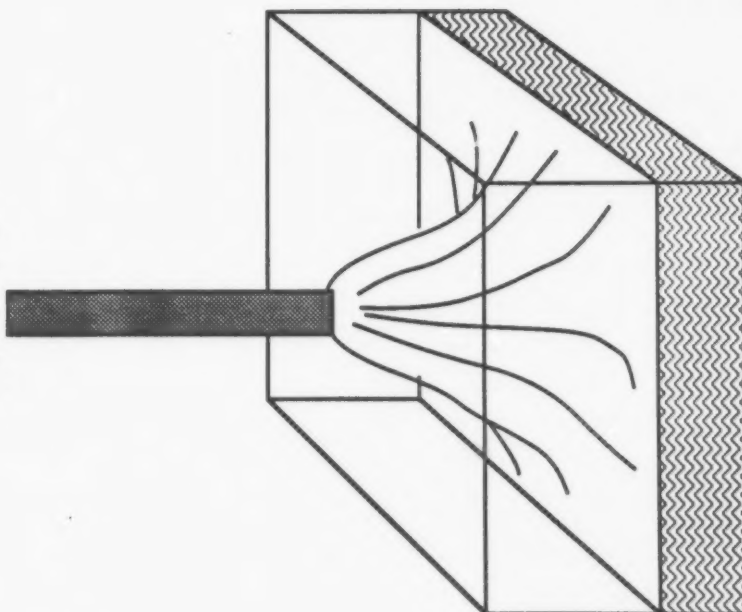
there will be a decrease in vertical flow resistance and an increase in oil production. Muskat accounted for reservoir anisotropy by modifying the vertical axis as $z' = h\sqrt{k_H/k_V}$ and defining the average or isotropic equivalent reservoir permeability as $\sqrt{k_H k_V}$. This modification leads to an elliptical wellbore. It has been shown that replacing the elliptical wellbore by a circular wellbore has a negligible effect on wellbore productivity. Based on the results of Giger et. al.⁸², for vertical anisotropy with k_V/k_H less than one, horizontal wells are not recommended. On the other hand, k_V/k_H values greater than one suggest favourable productivity conditions for horizontal wells which implies that there may possibly be vertical fractures in the reservoir.

Water Coning and Cresting

Production with horizontal wells offers a new approach to reduce the effect of water coning during oil production. Regardless of the method of production, one cannot ignore the "critical velocity" which when exceeded can lead rapidly to the entry of gas or water into the well when producing in a zone which comprises of a contact surface with water or gas near the well. Gas cones follow the same equations and patterns as water cones except that they form above the wells instead of below. The discussion hereafter concerns oil flow in the presence of bottom water so as to avoid repetition of the case of gas above oil.

Water coning, as shown in Figure 2.1, is due to pressure gradients resulting from the production of fluid from the reservoir. If a water-oil contact exists in the producing interval, these pressure gradients will induce water to rise in the immediate vicinity of a vertical well which acts as a single point in a horizontal plane. The tendency of the water to cone is offset or at least partially offset by gravitational forces because water has a higher specific gravity than oil. Thus, a balance exists between the gravity forces arising from the difference in the specific gravities of water and oil, and the pressure gradients causing the flow of fluid to the wellbore. When the pressure gradient exceeds the gravitational force, water coning to the wellbore occurs and water production occurs.

Vertical Well



Horizontal Well

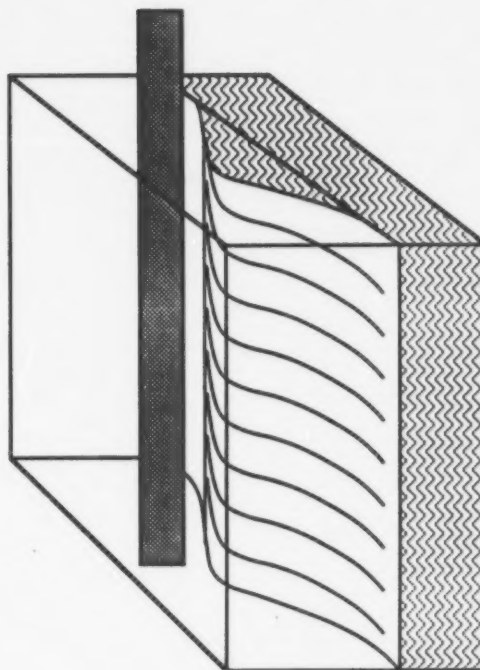


Figure 2.1: Water coning toward a vertical well and cresting toward a horizontal well.
(After Chaperon 78)

The general belief is that horizontal wells, which extend parallel to the initial oil-water contact, reduce coning tendencies because they generate more favourable flow conditions and shallower pressure gradients. Horizontal wells exhibit better performance because they require a much smaller pressure drawdown as compared to vertical wells to produce oil at the same rate yet they have an approximately linear pressure gradient from the wellbore to drainage radius. However, water may rise in horizontal wells in the form of crests instead of as cones; water cresting is shown in Figure 2.1. Figure 2.2(a) represents the cross-section of a reservoir prior to production while Figure 2.2(b) demonstrates water cresting caused by a bottom water drive.

Giger (1986⁸¹) determined the shape of the water oil contact (WOC) created by the development of a water crest in an oil column during production with a horizontal well based on the Dupuit-Forchheimer approximation. The shape of the water oil contact is an ellipse with a horizontal tangent close to its sides. Given the ordinate, y_G' , of the WOC at the lateral boundaries as in Figure 2.2(b), the WOC at some distance from the well is described as

$$y^2 - y_G'^2 + \frac{\mu_o q}{k_H \Delta \rho g D} \left(\frac{D}{2} - |x| \right)^2 = 0 \quad (2.4)$$

Below the well, the shape of the water crest is represented by a branch of the parabola; this is also the case far from the well. Therefore, when the ellipse is fitted with a Dupuit parabola in Figure 2.2(c), the following equation parabola is generated:

$$y^2 \left[\frac{c + \ln 2}{d} \right]^2 - \pi \frac{c + \ln 2}{d} - \frac{\pi^2}{12} - c^2 = 0 \quad (2.5)$$

where

$$c^2 = \pi^2 \left[\left(\frac{k_H \Delta \rho g}{\mu_o q} y_s' \right)^2 - \frac{k_H \Delta \rho g D}{\mu_o q} \frac{1}{4} - \frac{1}{12} \right] \quad (2.6)$$

and

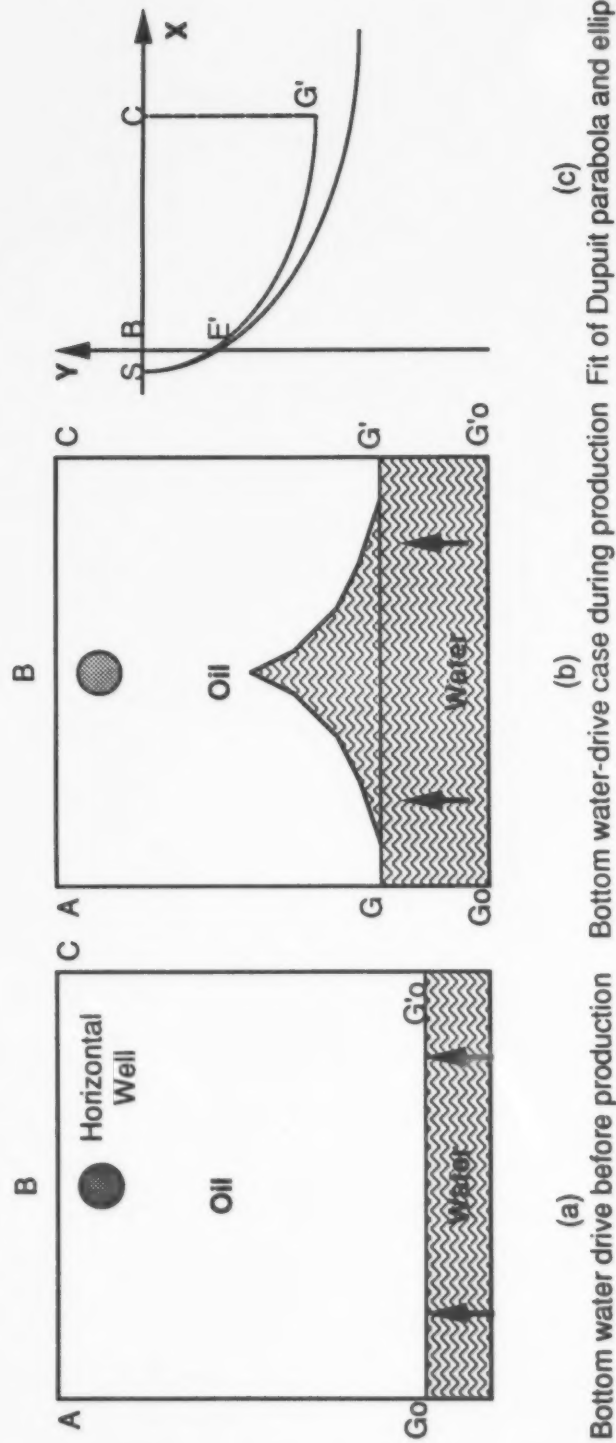


Figure 2.2: The Dupuit-Forchheimer approximation of the shape of a water crest during production with a horizontal well.
(After Giger 81)

$$d = \frac{\mu_o q}{k_H \Delta \rho g} \times \frac{c + \ln 2}{\pi} \quad (2.7)$$

From Equations (2.6) and (2.7), c and h are known and consequently, the shape of the WOC can be defined by Equation (2.5).

Giger (1986⁸¹) also defined the critical flow rate which signals the first drop of water entry into the well:

$$q_c = \frac{3}{2} \frac{k_H \Delta \rho g}{\mu_o} D \left[\left(1 + \frac{16}{3} \frac{y_s'^2}{D^2} \right)^{1/2} - 1 \right] \quad (2.8)$$

Equation (2.8) shows that as q_c decreases, $|y_s'|$ also decreases. In addition, q_c approaches the production rate until a time, t_c , at which it is equal to the production rate. Water begins to appear in the production at this time:

$$t_c = \frac{A_{sc}}{q_c} \phi (1 - S_w - S_{or}) \quad (2.9)$$

where

$$A_{sc} = -Dy_{G_i} + \frac{\mu_o q_c}{k_H \Delta \rho g} \left[\frac{D}{4\sqrt{3}} + \left\{ \left(\frac{k_H \Delta \rho g D}{\mu_o q_c} \frac{D}{4} + \frac{1}{12} \right) \times \left(\frac{\mu_o q_c D}{k_H \Delta \rho g} \right)^{1/2} \times \arccos \left(\frac{k_H \Delta \rho g D}{\mu_o q_c} \frac{D}{48} + \frac{1}{144} \right)^{-1/2} \right\} \right] \quad (2.10)$$

To prevent water production, the production rate of the horizontal well must be gradually reduced so that it will always be less than the critical flow rate with cumulative production.

Well Flow Behaviour

Early Time Flow Geometry of a Horizontal Well

Figure 2.3(a) shows that a horizontal well of length L has an ellipsoid drainage pattern. Joshi (1986⁸⁸) presented equations for early time horizontal well flow geometry, that is, until the first pressure transient reaches the upper or lower reservoir flow boundaries. Figures 2.3(b) and (c) schematically represent the method that Joshi uses to

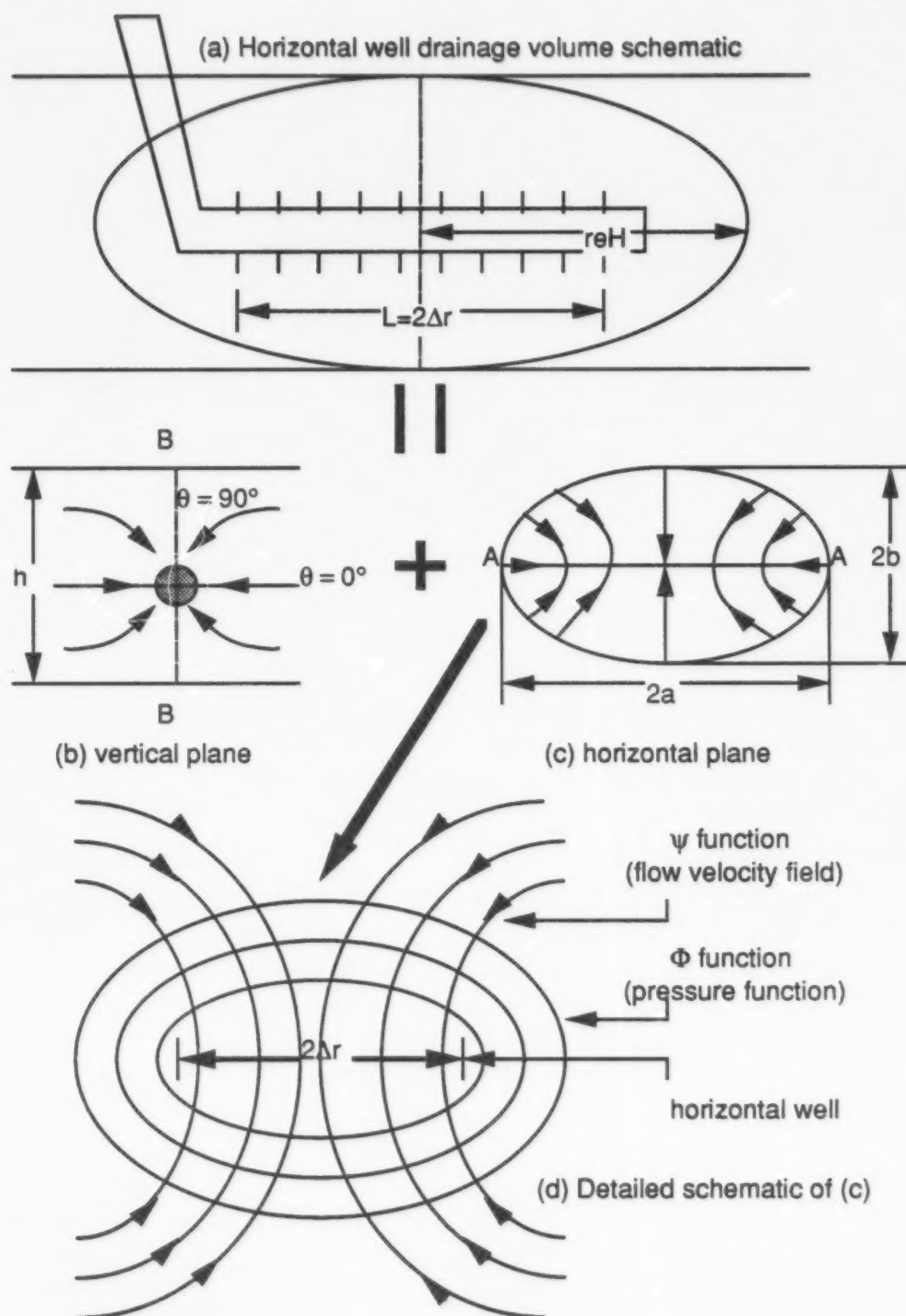


Figure 2.3: Schematic of potential flow to a horizontal well
(After Joshi 88)

simplify this problem. He subdivides the three dimensional ellipsoid problem into two, two dimensional problems: flow into a horizontal well in a horizontal plane and flow into a vertical plane. It is observed that the radius of the reservoir drained by this flow regime is approximately equal to half of the reservoir height. Joshi uses the potential flow theory presented by Muskat in Figure 2.3(d) for flow from an infinite reservoir into a finite line source to obtain the solution.

Figures 2.3(c) and (d) show a schematic diagram of flow to a horizontal well in the X-Y plane at early times. Joshi presents the equations for the equipotential function (Φ) which is represented by ellipses and the streamline function (ψ) which is expressed by hyperbolas:

$$w(z) = \Phi + i\psi = \cosh^{-1}(z/\Delta r) \quad (2.11)$$

where:

$$z = x + iy \quad (2.12)$$

$$\Phi = \cosh^{-1} H^* \quad (2.13)$$

$$\psi = \cos^{-1} H^* \quad (2.14)$$

$$H^* = \left[\frac{x^2 + y^2 + \Delta r^2 \pm \sqrt{(x^2 + y^2 + \Delta r^2)^2 - 4\Delta r^2 x^2}}{2\Delta r^2} \right]^{1/2} \quad (2.15)$$

He then gives the equation for flow into a horizontal plane:

$$q_1 = \frac{2\pi k_o \Delta p / \mu}{\ln \left[\frac{a + \sqrt{a^2 - \Delta r^2}}{\Delta r} \right]} \quad (2.16)$$

From Figure 2.3(b), which schematically demonstrates flow in a vertical plane (X-Z), Joshi obtains:

$$w(z) = \Phi + i\psi = q \left[\left(\frac{\pi r}{h} \right) \cos \theta - \ln \left(\frac{\pi r}{h} \right) \right] + iq \left[\left(\frac{\pi r}{h} \right) \sin \theta - \theta \right] \quad (2.17)$$

The flow into a horizontal well in the vertical plane is given as

$$q_2 = \frac{2\pi k_o \Delta p / \mu}{\ln \left[\frac{h}{2r_w} \right]} \quad (2.18)$$

Joshi multiplies the two flow equations (Equation 2.16 and 2.18) by the reservoir height, h , and uses an electric analog concept to calculate flow resistance in the horizontal and vertical planes. He adds the horizontal and vertical flow resistances to obtain the equation for flow into a horizontal well in the early time flow regime:

$$q_h = \frac{\left(\frac{2\pi k_o h \Delta p}{\mu B_o} \right)}{\ln \left(\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2} \right) + \frac{h}{L} \ln \left(\frac{h}{2r_w} \right)} \quad (2.19)$$

where

$$a = \frac{L}{2} \times \left[\frac{1}{2} + \sqrt{\frac{1}{4} + \frac{1}{\left(0.5L/r_{eH} \right)^4}} \right]^{0.5} \quad (2.20)$$

Late Time Flow Geometry of a Horizontal Well

Figure 2.4(c) depicts the flow geometry in the final flow period at which time flow is almost completely linear everywhere outside the well. This flow regime is known as plane parallel flow and is caused by the pressure response in the reservoir in response to the effects of the lateral boundaries. It should be noted, however, that radial flow still dominates in the immediate vicinity of the wellbore.

It has been determined that if the length of the horizontal well is significantly larger than the height of the reservoir ($L/h \gg 1$), then the production from a horizontal well can be considered to be equivalent to the production from a fully penetrating vertical fracture (Joshi, 1986⁸⁸; Goode and Thambynayagam, 1987⁸³).

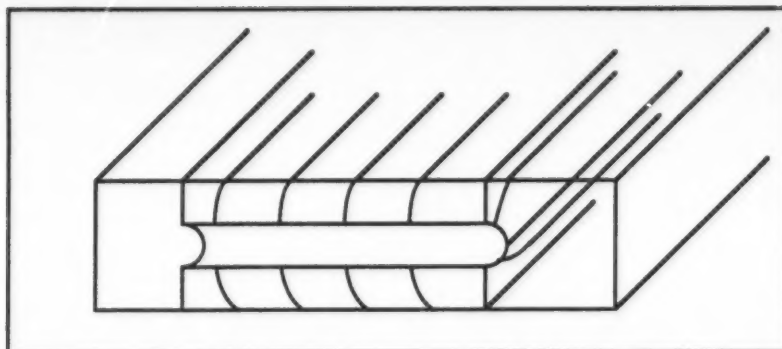


Figure 2.4 (a): Intermediate-time linear flow.

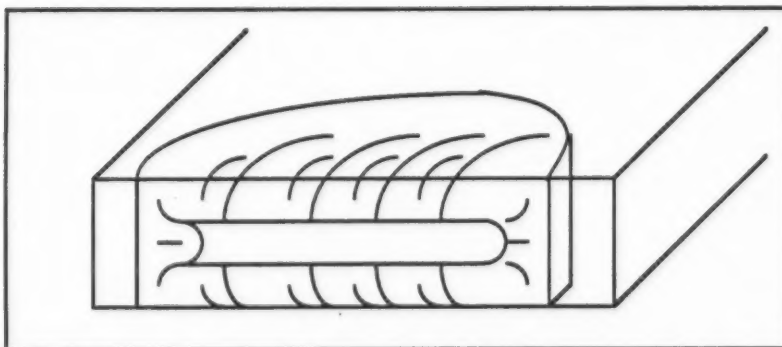


Figure 2.4 (b): Late-intermediate-time linear flow.

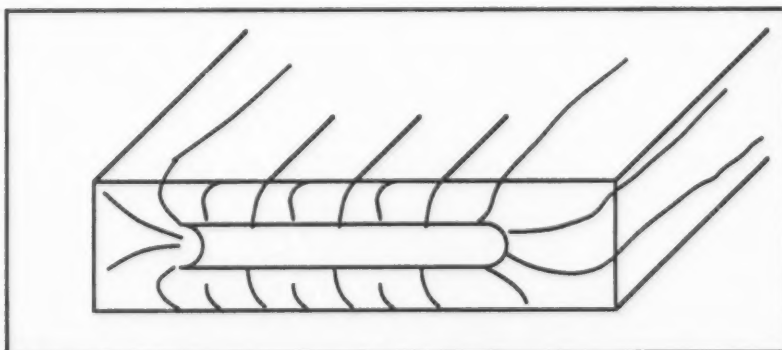


Figure 2.4 (c): Late-time linear flow.
(After Goode and Thambynayagam 83)

Gravity Drainage

In cyclic steam stimulation, the dominant production mechanism is the pressure gradient between the reservoir and production well. In steam stimulation, oil production rates are governed by the pressure gradient between the injection and production wells. However, in steam assisted gravity drainage, the only pressure drop is due to the gravity head between the injection and production wells. Therefore, oil production is controlled solely by gravity drainage and the rate of gravity drainage is enhanced by a reduction in oil viscosity resulting from steam heating. The steam assisted drainage concept as introduced by Butler will be discussed as it relates to horizontal wells.

Consider Figure 2.5, which shows a horizontal well pair located near the bottom of an oil column with the injection well above the production well. The wells are placed as close as possible to each other in order to eliminate the pressure gradient and maximize the gravity head between them. The basic idea is that steam is introduced to the upper injection well which is located near the bottom of the reservoir. It is believed that the steam will rise, heat the surrounding formation and hence reduce the viscosity of the oil. The heavier condensates and the heated oil will fall to the lower production well as a result of the gravity drainage mechanism; the fluids will be drained purely by gravity. The pressure within the steam chamber will essentially remain constant. The steam chamber will continue to grow upwards and sideways as the oil is produced. Butler et. al. (1981⁷⁶) discovered that the rate of growth upwards of the steam chamber is larger than that sideways. However, the upwards growth would eventually be limited to the top of the reservoir at which time sideways growth would become the critical consideration. Figure 2.6 represents the expected growth of steam chambers above adjacent horizontal wells. The chambers will grow until they reach the top of the reservoir. They will then spread sideways and intermingle to form a single steam layer above the oil.

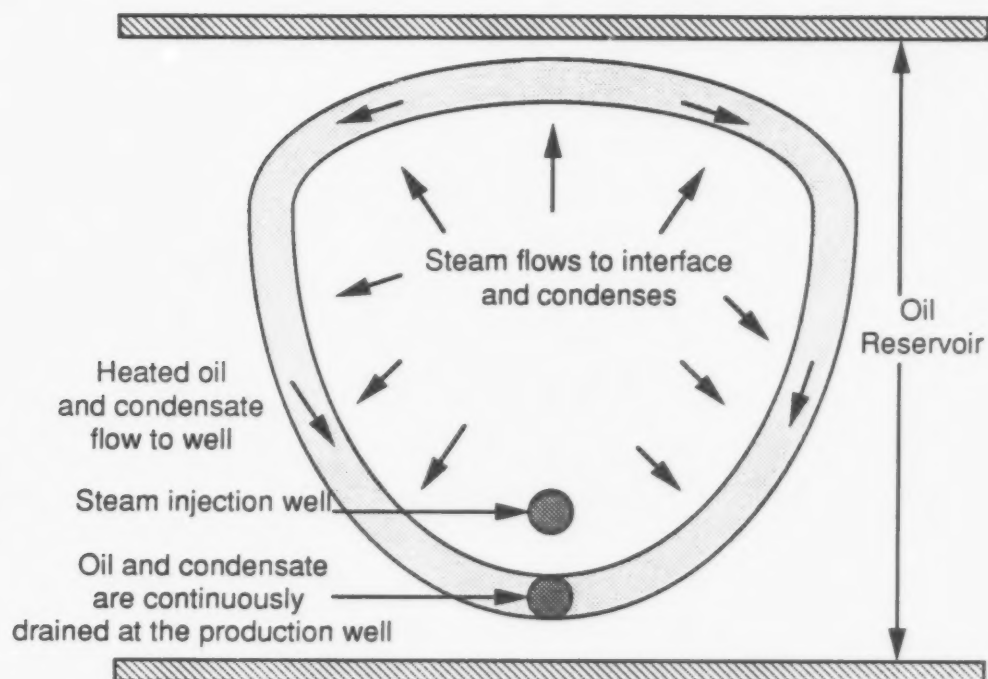


Figure 2.5: Steam assisted gravity drainage concept applied to a horizontal well pair. (After Joshi 89)

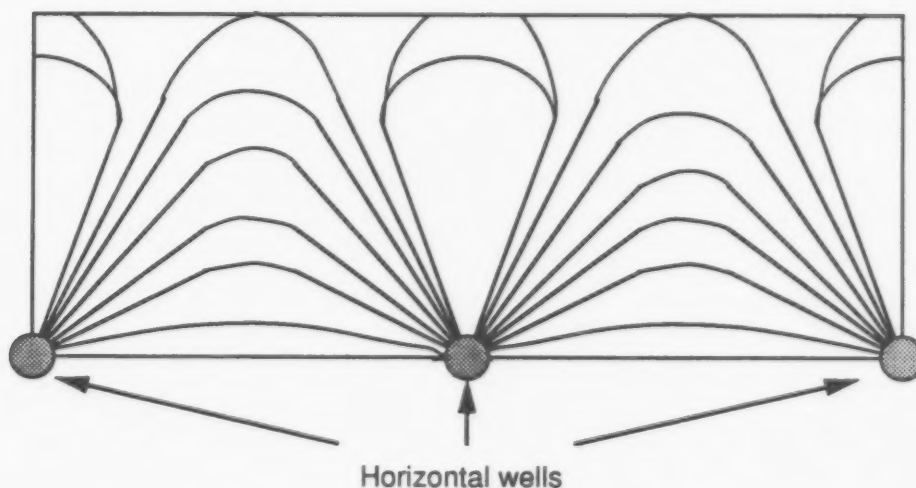


Figure 2.6: Steam growth chamber above adjacent horizontal wells. (After Butler, McNab and Lo 76)

The obvious advantage of steam assisted gravity drainage is the high displacement efficiency and thus, increased recovery due to improved sweep efficiency. Furthermore, hot oil is produced as soon as it is displaced from the formation which differs from cyclic steam stimulation and steam drives. Favourable relative permeability conditions for oil flow are created as a result of the creation of independent flow paths for oil, condensed water and steam. An additional advantage of the process is that injection can be stopped and reinitiated without any significant loss in the recovery efficiency in the event of early steam breakthrough.

The negative aspects of gravity drainage are that it requires a relatively thick oil column (≈ 15 m) and it may be hindered in zones separated by thick, continuous shale layers. In the latter case, horizontal wells may have to be drilled in each layer that is to be drained.

Butler (Joshi, 1986⁸⁹) developed a semi-analytical solution to calculate oil production and oil-steam ratios (OSR) for parallel horizontal wells. He also studied three possible well configuration schemes for field applications which are shown in Figure 2.7. Butler's results indicate that the optimum well scheme for reservoirs with non-continuous shale barriers is the scheme (Figure 2.7 (c)) with vertical injectors and a horizontal producer .

Well Patterns

Steam override is a phenomenon of steamflooding processes. It results primarily from the density differential between the low density steam and the other reservoir fluids. Steam rises to the top of the formation and sweeps the upper portion of the reservoir. In the lower portion of the reservoir, however, only condensing hot water or bypassed injection fluid will sweep this zone. Consequently, high oil saturation zones in the lower portion of the reservoir can remain after a steamflood. These oil pockets or blind spots are usually recovered by infill drilling. Horizontal wells used in combination with vertical

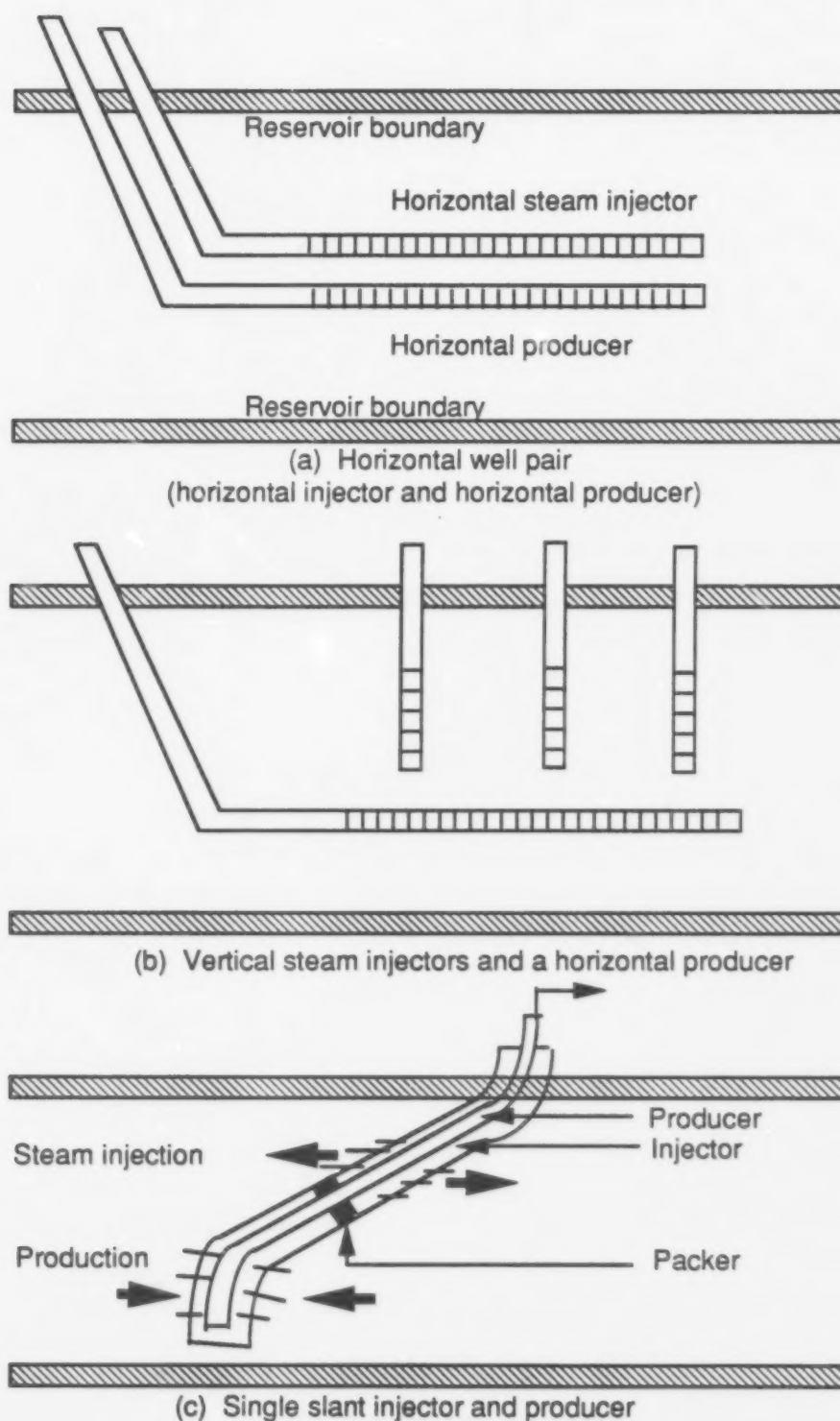


Figure 2.7: Different well configuration schemes for steam assisted gravity drainage.
(After Joshi 89)

wells provide a way to improve the overall sweep efficiency and thus, reduce the occurrences of blind spots. The following discussion on well configurations are based on numerical simulation studies.

Figure 2.8 represents three horizontal well configurations studied by Gussis (Joshi, 1986⁸⁹). The first pattern scheme, (Figure 2.8(a)), a line drive, considers the effects of drilling a series of injection and production wells at the base of the reservoir. The second pattern (Figure 2.8(b)) drills the injectors at the bottom and the producers at the top of the reservoir to produce a consecutive line drive. Finally, in Scheme III (Figure 2.8(c)), he examines the effects of drilling eight wells radially outward from the center of a square drainage area. Pattern II loses too much heat to the overburden near the top of the reservoir while in pattern III, the large distance between well tips at the outer boundary causes poor sweep near the out reservoir boundary and thus, poor recovery. It was concluded, strictly from a recovery standpoint, that Scheme I produces the best results. This was the scheme used for the horizontal well steam injection experiments in the Aberfeldy low pressure model.

Huang and Hight (1986⁸⁶) examine the vertical and horizontal well combinations shown in Figure 2.9. Figure 2.9(a) represents three vertical injection wells and two horizontal wells per pattern. This pattern configuration (C-1) uses the horizontal wells to draw fluid to the bottom of the reservoir to effectively reduce the steam override phenomenon. Configuration C-2 (Figure 2.9(b)) has two vertical injectors and two horizontal producers per pattern. In this case, Huang and Hight discovered that a small blind spot remains along the diagonal midway between the injection wells. Horizontal wells are placed along the outside edges and diagonally through the centre of a square pattern in Figure 2.9(c) (Configuration C-3). Here, there are two vertical injectors and three horizontal producers per pattern. It was determined that some steam override occurred leaving a small blind spot area at the ends of the central horizontal well. While pattern configuration C-2 provides the highest oil recovery (73.1% OOIP), pattern C-3 has

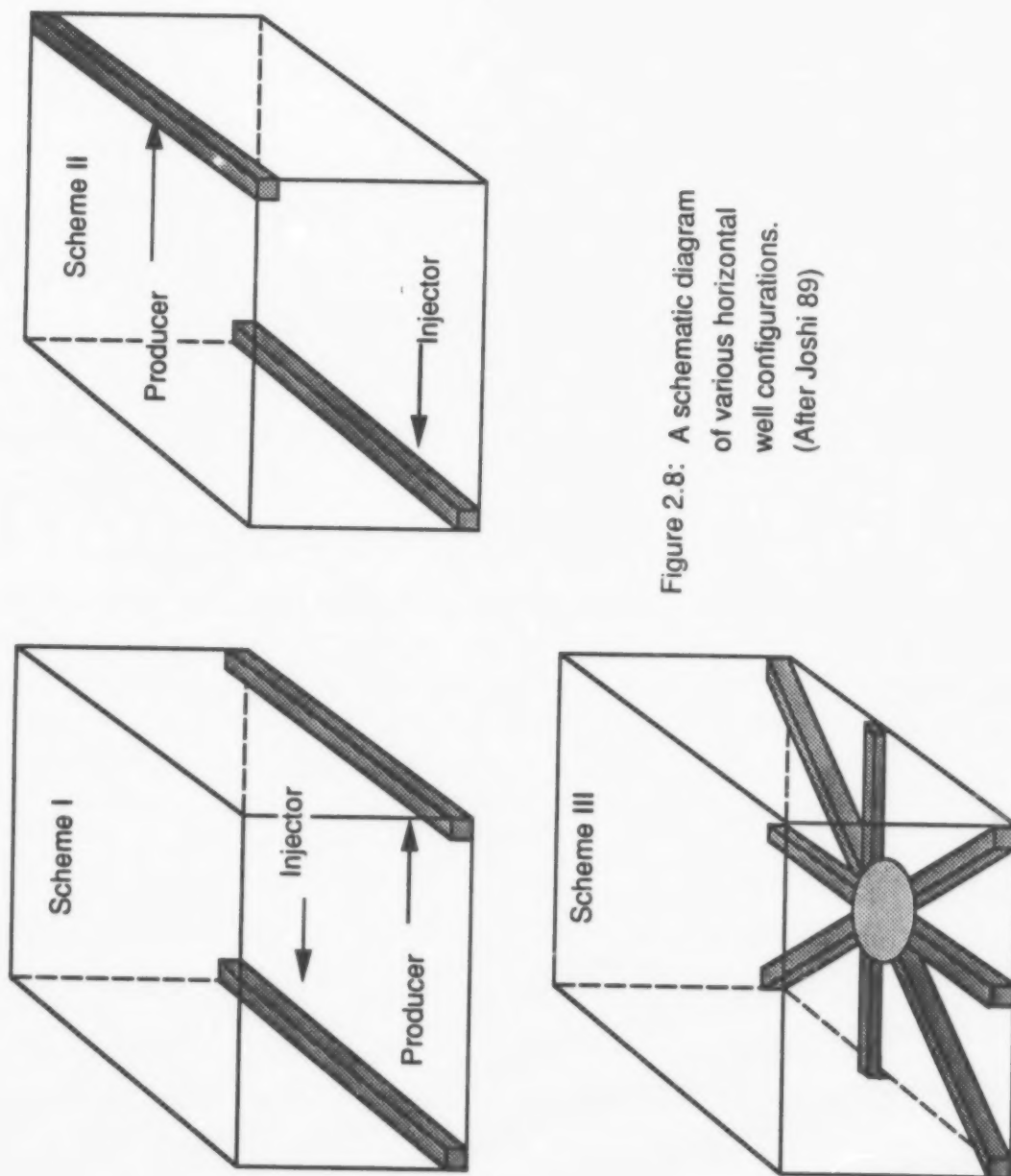


Figure 2.8: A schematic diagram of various horizontal well configurations. (After Joshi 89)

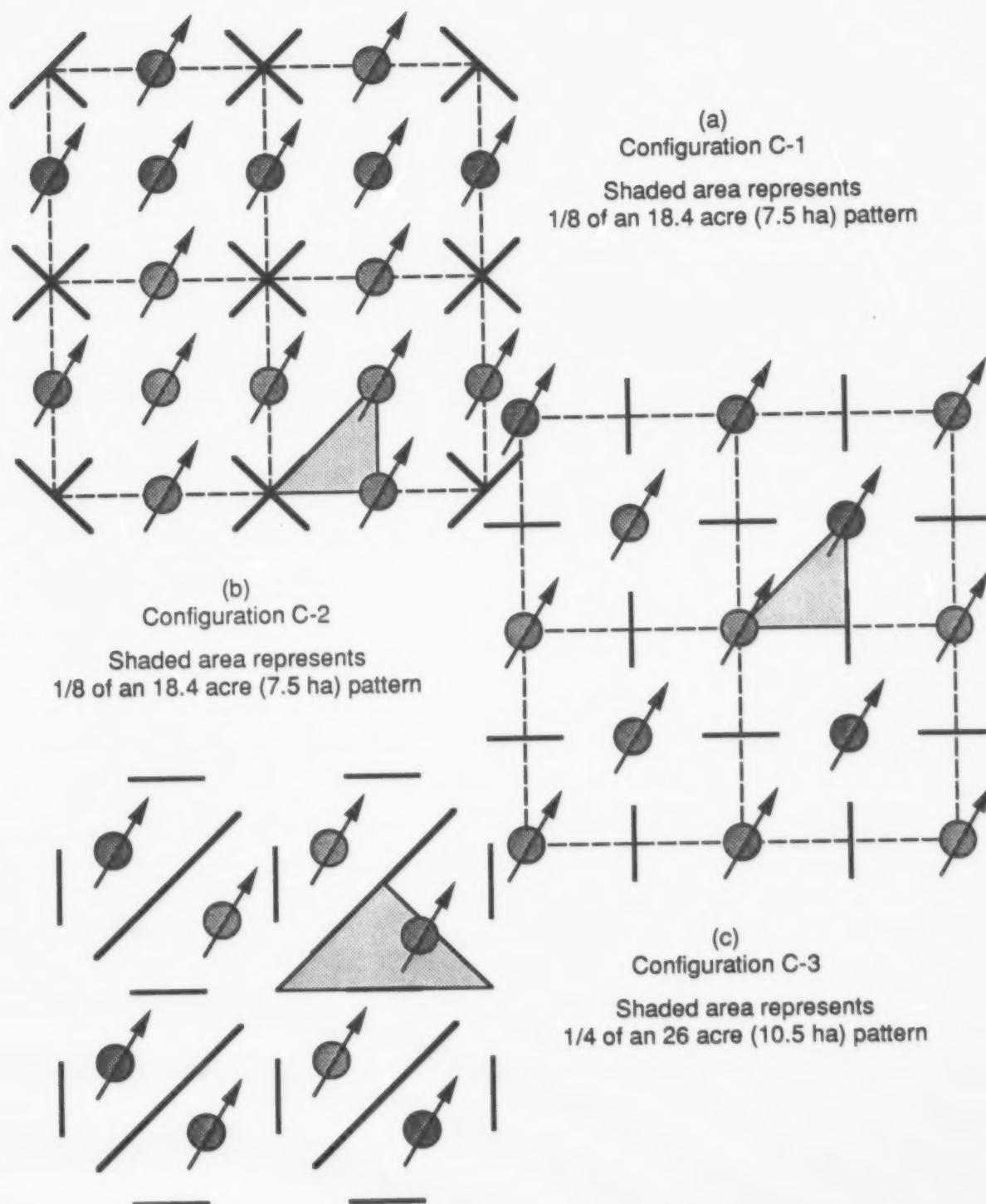


Figure 2.9: Combination of vertical and horizontal well patterns.
(After Huang and Hight 86)

the lowest development cost per barrel of oil recovered. Obviously, the validity of the simulation studies are high dependent on the ability of horizontal wells to perform well in field service as well as the economic feasibility of horizontal well technology.

Chapter 3

Scaling Parameters and Calculations

The development of scaled physical models is based on the recognition that dimensional similarities between prototype and model systems exert control over the geometrical, mechanical, thermal and chemical phenomenon ongoing within. This concept of dimensional similarity, as applied by Stegemeier, Laumbach and Volek⁹ through the principle of inspectional analysis, was used in the development of the scaling parameters. The development of the parametric scaling principles required corresponding model and prototype similarities at the physical and dynamic points within the system. The following chapter discusses the techniques used to implement this scaling method and also presents examples of its application.

Development of Scaling Parameters for the Low Pressure Model

Unscaled Parameters

Scaled physical laboratory models, like numerical models, are developed under certain physical constraints which unfortunately lead to approximations and simplifications in the final product. These simplifications are necessary in order to achieve greater ease in the handling of the problem and are based on the best current understanding of the process dynamics. Hence, as a result of the compromises in engineering judgement required to match the scaled model and field prototype, it is impossible to satisfy all of the similarity parameters simultaneously. Consequently, a reduced number of parameters known as scaling parameters were generated.

The parameters which were not scaled between the model and prototype systems in this study are:

1. steam distillation of the crude oil
2. capillary pressure and relative permeability

3. thermal expansion and compression of the reservoir fluids and matrix
4. the extent of emulsification and its mechanism
5. specifications corresponding to the injection and production of a horizontal well (such as pressure drop within and around the vicinity of the wellbore, skin factor, most desirable perforation intervals)
6. effects of asphaltene flocculation

For strict scaling, the relative permeability and capillary pressure relationship would have to be the same functions of saturation in both the model and prototype. Unfortunately, they cannot be scaled in an unconsolidated bead pack as their values may differ greatly from those of the prototype and thus, could have a significant effect on the displacement processes (Doscher and Huang^{22,24,114}). Prats¹¹ stated that the failure to scale relative permeability resulted in the inability to determine the three-phase curves for the prototype under the anticipated operating conditions. Yet, despite this limitation, Prats¹¹ produced favourable correlations between the Peace River scaled physical model and prototype. It was believed that capillary pressure scaling was not required for a prototype with a high viscosity crude oil since the breakthrough recovery, as stated by Demetre et. al.⁵⁸ is only a weak function of the capillary number when the mobility ratio is large and the displacement is stable.

The scaling of the parameters stated above could be more readily addressed by a high pressure system where pressure, temperature, fluid and matrix components could be made. However, the success of vacuum model studies imply that the listed phenomena have only a second order effect on the mechanical processes involved in the production of viscous crude oils resulting from steamflood process. It is noted that while these phenomena may not be actively scaled, they may occur and/or exist during the steam drive process.

Scaling Procedures

The procedure that Stegemeier, Laumabach and Volek used to obtain the scaling parameters in Table 3.1 for modeling the steam drive processes was to:

1. formulate the governing equations (partial differential, constraint, constitutive and auxiliary equations) in dimensionless form (m_D) by dividing the dimensional variables (m) by a suitable reference quantity (m_R). Thus:

$$m_D = \frac{m}{m_R} \quad (3.1)$$

2. identify the set of similarity parameters by inspectional analysis
3. obtain a set of scaling parameters by combining and modifying, based on engineering judgement, the similarity parameters which could be matched between the scaled model and field prototype

Stegemeier et. al.⁹ made the following assumptions when deriving the scaling criteria in Equations (3.2) to (3.17) for the low pressure model:

1. three phases consisting of oleic, aqueous and steam phase (no volatile hydrocarbons) may exist
2. there is no partitioning into or out of the oil phase (dead oil assumption)
3. rock compressibility and thermal expansion are negligible
4. Darcy's and Fourier's equations are valid
5. capillary pressure effects are negligible
6. the system is in local thermodynamic equilibrium
7. kinetic energy, potential energy and dissipation energy are negligible compared with the thermal energy
8. the enthalpy and internal energy are linear functions of temperature and are essentially equal for the oleic phase and aqueous phase
9. the difference between the steam enthalpy and internal energy can be neglected

Table 3.1: Scaling Parameters for Steam Processes

<u>Number</u>	<u>Scaling Parameter</u>	<u>Name of Scaling Parameter</u>
1.	$\frac{P_R}{\rho_R g_R L_R}$	Poiseuille Number divided by Stokes number
2.	$\left(\frac{f_R L_{vt}}{C_R T_R} + 1 \right) \times A^*$	Modified Jacob Number + 1
3.	$\frac{f_{sR} \mu_{sR} \rho_R}{\mu_R \rho_{sR}}$	Ratio of steam pressure gradient to oil pressure gradient
4.	$\frac{k_{sR} t_R}{\phi_R S_R \rho_R C_R L_R^2} \times A^*$	Fourier Number or Peclet Number
5.	$\frac{\phi_R S_R \mu_R L_R}{k_R \rho_R g_R t_R}$	Stokes Number
6.	$\frac{w_R t_R}{\rho_R \phi_R S_R L_R^3}$	Poiseuille Number divided by Modified Poiseuille Number

* Subscript 'R' denotes the reference variable used to obtain a dimensionless term.

** When $\phi \Delta S$ is not matched, A takes on a value between unity and $\phi_R S_R \left(\frac{\rho_R C_R}{\rho_{cR} C_{cR}} \right)$.

~ If reservoir heating or heat production predominates, use unity.

~ If cap and base rock heating predominates, then use $\phi_R S_R \left(\frac{\rho_R C_R}{\rho_{cR} C_{cR}} \right)$.

(After Stegemeier, Laumbach and Volek⁹)

10. the time rate of change of the specific steam enthalpy in the steam zone is negligible
11. the internal energy of the rock is a linear function of temperature
12. the saturated steam temperature is the maximum temperature at any location
13. relative permeabilities depend exclusively on the saturations
14. S_{ors} and S_{wc} are constant and uniform throughout the model
15. critical saturation for steam flow is assumed to be zero
16. the changes in the density of the immovable water and residual oil are negligible

Using the above assumptions and applying the conservation of mass balance to the oil phase, denoted by the subscript 'o', yielded:

$$\phi \frac{\partial(\rho_o S_o)}{\partial t} + \nabla \cdot (\rho_o \bar{u}_o) = 0 \quad (3.2)$$

The continuity equation for water, including both liquid and vapour (steam) phases signified by subscript 'w' for water in the liquid phase and 's' for the vapour, was:

$$\phi \frac{\partial(\rho_w S_w)}{\partial t} + \nabla \cdot (\rho_w \bar{u}_w) + \phi \frac{\partial(\rho_s S_s)}{\partial t} + \nabla \cdot (\rho_s \bar{u}_s) = 0 \quad (3.3)$$

From the assumption that Darcy's equation was valid, the following equation was written for any species j , where $j=o, w$, or s :

$$\bar{u}_j = -\frac{k k_r}{\mu_j} (\nabla p - \rho_j \bar{g}) \quad (3.4)$$

The conservation of energy for the reservoir was expressed by

$$\begin{aligned} & [(1-\phi)\rho_r C_r + \phi(\rho_o C_o S_o + \rho_w C_w S_w)] \frac{\partial T}{\partial t} + L_v \left[\phi \frac{\partial(\rho_s S_s)}{\partial t} + \nabla \cdot (\rho_s \bar{u}_s) \right] \\ & + (\rho_o C_o \bar{u}_o + \rho_w C_w \bar{u}_w) \cdot \nabla T + \rho_s \bar{u}_s \cdot \nabla h_s + \nabla \cdot \bar{q} = 0 \end{aligned} \quad (3.5)$$

The Fourier equation represented the conductive heat flux by

$$\bar{q} = -k_h \nabla T \quad (3.6)$$

When all the saturations were present, the constraint equation became

$$S_o + S_w + S_s = 1 \quad (3.7)$$

The functional form of Clausius-Clapeyron relationship at saturated conditions, where pressure and temperature are interdependent, can be written as:

$$p_{\text{sat}} = p_{\text{sat}}(T_{\text{sat}}) \quad (3.8)$$

The remaining constitutive equations required to describe the dependence of the material properties in the reservoir system on the thermodynamic-state variables were expressed in their functional forms as

$$\phi = \phi(x, y, z) \quad (3.9)$$

$$\rho_j = \rho_j(p, T) \quad (3.10)$$

$$k = k(x, y, z) \quad (3.11)$$

$$k_{rj} = k_{rj}(S) \quad (3.12)$$

$$\mu_j = \mu_j(T) \quad (3.13)$$

$$h_s = h_s(T) \quad (3.14)$$

$$L_v = L_v(T) \quad (3.15)$$

$$k_h = k_h(x, y, z) \quad (3.16)$$

$$\rho_r = \rho_r(x, y, z) \quad (3.17)$$

where 'S' denotes phase saturation dependence.

Calculation of Parametric Values for the Aberfeldy Low Pressure Model

Prototype and Model Correlations

The design of the vacuum model involved the selection of representative prototype values that were typical of the Aberfeldy heavy oil reservoir. The calculations used to scale the prototype data to model values are expressed in this section. A summary of the Aberfeldy prototype and model values are given in Table 3.2.

Table 3.2: Summary of Scaling Parameters for Steam Processes

<u>Aberfeldy Field Property</u>	<u>Prototype Value</u>	<u>Model Value</u>
Well Spacing	8 hectare (20 acre), 5-spot	1/4 of 5-spot
Depth of Reservoir	522.4 m	—
Net Pay Thickness	11 m	6.32 cm
Gross Pay	Varies from 10 to 13 m	6.32 cm
Porosity	31%	32.1%
Permeability	2000 md	5390.2 d
Thermal Conductivity	0.002077 kW/m•K (1.2 BTU/hr•ft•°F)	0.003266 kW/m•K
Heat Capacity	2.2217 kJ/kg•K	2.3824 kJ/kg•K
Initial Fluid Saturations	$S_o = 0.75$ $S_w = 0.23$ $S_g = 0.02$	$S_o = 0.85$ $S_w = 0.10$ $S_g = 0.05$
Steamflood Residual Oil Saturation	$S_{or} = 0.15$	$S_{or} = 0.05$
Oil Viscosity	1275 mPa•s at 23.9°C 560 mPa•s at 32.2°C 90 mPa•s at 65.6°C 12.5 mPa•s at 135.0°C 1.29 mPa•s at 301.7°C	9257 mPa•s at 3.2°C 243 mPa•s at 22.9°C
Water Viscosity	0.891 mPa•s at 25.8°C	0.891 mPa•s at 25.8°C
Gas Viscosity	0.013 mPa•s at 23.3°C 0.016 mPa•s at 134.4°C	—
Specific Gravity of Gas	0.55	—
Initial Reservoir Temperature	23.3°C	3.0°C
Initial Reservoir Pressure	3.45 MPa	0.0267 MPa
Steam Injection Pressure	1.9 MPa	—
Steam Injection Rate	100 - 150 m ³ /D	247.49 cm ³ /min
Steam Quality	0.70 (Actually f_{st} is 0.80 to 0.85, but a lower value was used to compensate for wellbore heat loss)	0.093
Solvent Injection Rate	80.81 m ³ /D	200 cm ³ /min
Pressure Range	Upper Range: fracture gradient of reservoir Lower Range: bottom hole production pressure (0.345 MPa (50 psia) back pressure	Lower Range: 0.006895 MPa (1 psia)

Length Scale Selection

Since it was assumed that the model element of symmetry and the prototype are geometrically similar, the scaling factor was defined as the ratio of the dimensions of the model and prototype. The length scale for a prototype with a production pressure of 100 psia or less, $\gamma(L)$, was dependent on the temperature-pressure relationships and the physical constraints placed on the model size. Stegemeier et. al. recommended that the best match between the pressure-temperature correlation for saturated steam could be achieved by making $\gamma(L)$ as small as possible and thus, the model as large as possible within the practical limitations of cost and time to prepare the model. In addition, the increased probability of leaks and the necessity for larger structural requirements for larger models, were also considered. Hence, the selection of the length scale was taken to be somewhat arbitrary.

The model used in the study represented one-quarter of an eight hectare five-spot in the Aberfeldy heavy oil reservoir. The prototype length, L_p , for the 2 ha section was determined to be 141.42 m corresponded to 32 inches (81.28 cm) in the model, L_m . Since the prototype and model were geometrically similar, the length scale was calculated as

$$\frac{L_p}{L_m} = \gamma(L) = 173.99 \quad (3.18)$$

Applying the length scale in three dimensions, the model thickness representing the prototype thickness of 11 m was 6.32 cm (2.5 in).

Model Pressure Scaling

The most difficult relationship to match is the Clausius-Clapeyron temperature-pressure relation. The result of not scaling the Clausius-Clapeyron relation is that the temperature and pressure will not correspond at all points within the steam zone. This problem is overcome by operating the model at subatmospheric pressure levels and low temperatures. Thus, for typical prototype length scales of 100 to 200 and pressures as low

as 0.345 MPa (50 psia), the best match can be obtained by selecting the lowest possible model production pressure value. From a practical standpoint, the lowest pressure that can be maintained is limited by the vapour pressure and physical constraints of vacuum pump is approximately 1 psia.

From the parametric equality:

$$\gamma(\Delta p) = \frac{(p - p_p)_p}{(p - p_m)_m} = \frac{\rho_p g_p L_p}{\rho_m g_m L_m} \quad (3.19)$$

where: $\frac{L_p}{L_m} = \gamma(L) = 173.99 \quad (3.18)$

$$\gamma(\rho_r) = \frac{\rho_p}{\rho_m} = 0.9 \quad (3.20)$$

$$\gamma(g_r) = \frac{g_p}{g_m} = 1.0 \quad (3.21)$$

$$(p_p)_m = 0.345 \text{ MPa (50 psia)} \quad (3.22)$$

$$(p_p)_p = 6.895 \text{ kPa (1 psia)} \quad (3.23)$$

Table 3.3 is obtained by substituting the identities in equations (3.18) and (3.20) through (3.23) into equation (3.19) to obtain the model pressure relation as a function of the prototype pressure, where p_m and p_p are in MPa:

$$\frac{(p - 0.345 \text{ MPa})_p}{(p - 0.006895 \text{ MPa})_m} = 0.9 \times 1.0 \times 173.2$$

which reduces to: $p_m = 0.004692 + 0.006386 p_p \quad (3.24)$

Model Temperature Scaling

In order to obtain the best match between the model and prototype oil viscosity curves, it is desirable to make the model temperature range as large as possible and hence, the initial model temperature as low as possible. However, from a practical standpoint, the

minimum initial model temperature $(T_0)_m$ is about 3°C since cooling below this range will result in localized freezing of the model.

Stegemeier et. al.⁹ recommends selecting a value in the middle of the pressure range when calculating the temperature difference ratio since the majority of oil production will occur when these temperatures are significant. This is further supported by the fact that a poor fit is achieved for steam in the lower portion of the pressure-temperature relation.

From the relation:

$$\frac{(\Delta T)_p}{(\Delta T)_m} = \frac{(T_p - T_R)_p}{(T_m - T_R)_m} = \frac{(T_s - T_R)_p}{(T_s - T_R)_m} \quad (3.25)$$

and using the midrange prototype and model temperatures from Table 3.3:

$$(T_R)_p = 23.3^\circ\text{C}$$

$$(T_R)_m = 3.0^\circ\text{C}$$

$$(T_s)_p = 212.42^\circ\text{C (at 2.0 MPa)}$$

$$(T_s)_m = 56.97^\circ\text{C (at 0.0175 MPa)}$$

substitution leads to
$$\frac{\Delta T_p}{\Delta T_m} = \frac{212.42^\circ\text{C} - 23.3^\circ\text{C}}{56.97^\circ\text{C} - 3.0^\circ\text{C}}$$

which yields the identity
$$\frac{\Delta T_p}{\Delta T_m} = 3.5 \quad (3.26)$$

To have the proper proportion of energy stored as internal energy, this ratio must be constant over the temperature range so

$$\frac{(T_p - 23.3^\circ\text{C})_p}{(T_m - 3.0^\circ\text{C})_m} = 3.5$$

Thus,
$$T_m = 0.286T_p - 3.657 \quad (3.27)$$

As is noted from Table 3.3, the calculated values, T_{sc} , do not correspond exactly with the saturation temperatures, T_s . Stegemeier⁹ suggests better scaling is achieved by allowing the error to occur at lower temperatures.

Table 3.3: Prototype and Model Scaling Values

Prototype Values										Model Values								
p (MPa)	T_s (C)	hw (kJ/kg)	$Cw\Delta T$ (kJ/kg)	L_v (kJ/kg)	ds (kg/m ³)	μ_s (cp)	p (MPa)	T_s (C)	T_{sc} (C)	hw (kJ/kg)	$Cw\Delta T$ (kJ/kg)	L_v (kJ/kg)	ds (kg/m ³)	μ_s (cp)	f_s	μ_{om}/μ_{op} (cp/cp)	w/wt	h_{ss} kJ/kg
*	*	*	*	*	*	**	Eq.3.23	*	Eq.3.27	*	*	*	*	**	Eq.3.37	Eq.3.39	Eq.3.38	***
3.45	241.73	1045.6	949.1	1757.9	19.220	0.0175	0.0267	66.39	65.48	277.9	265.3	2342.8	0.170	0.0112	0.070	8.02	0.8734	2723.5
3.00	233.90	1008.4	911.9	1795.7	14.997	0.0173	0.0239	63.83	63.24	267.2	254.6	2349.1	0.153	0.0111	0.073	7.33	0.8744	2723.8
2.50	223.99	962.1	865.6	1841.0	12.508	0.0169	0.0207	60.84	60.40	254.1	241.5	2356.7	0.134	0.0110	0.077	7.44	0.8756	2724.1
2.00	212.42	908.8	812.3	1890.7	10.037	0.0165	0.0175	56.97	57.10	238.5	225.9	2365.8	0.113	0.0109	0.081	7.56	0.8775	2724.4
1.50	198.32	844.9	748.4	1947.3	7.589	0.0160	0.0143	52.40	53.06	220.9	208.3	2376.0	0.094	0.0107	0.087	7.47	0.8792	2724.7
1.00	179.91	762.8	666.3	2015.3	5.143	0.0153	0.0111	47.85	47.80	199.1	186.6	2388.6	0.073	0.0106	0.093	7.17	0.8809	2725.1
0.50	151.86	640.2	543.7	2108.5	2.667	0.0143	0.0079	41.13	39.77	172.3	159.7	2404.0	0.054	0.0103	0.107	6.07	0.8777	2725.4
0.345	138.36	582.0	485.5	2149.7	0.532	0.0138	0.0069	38.45	35.91	161.1	148.5	2410.4	0.046	0.0102	0.116	1.60	0.8736	2725.5

* "Fundamentals of Classical Thermodynamics", 3rd Ed., SI Version by G.J. Van Wylen and R.E. Sonntag (1985) (111)

** After Farouq Ali (70): $\mu_s = (0.2T + 81.97) \times 10^{-4}$ where T in °F, μ_s in cp and $T(^{\circ}\text{F}) = 9/5T(^{\circ}\text{C}) + 32$

*** "Thermodynamic Properties in SI", Department of Mechanical Engineering, Stanford University (112)

Time Scale Determination

Using the dimensionless parameter (4) in Table 3.1 and assuming that the heating of the cap and base rock predominates such that $A^* = \phi_R S_R (\rho_R C_R / \rho_{cR} C_{cR})$, Stegemeier et. al.⁹ developed the following time scale ratio:

$$\frac{t_m}{t_p} = \left(\frac{k_{hp}}{k_{hm}} \right) \left(\frac{\rho_{cm} C_{cm}}{\rho_{cp} C_{cp}} \right) \left(\frac{L_m}{L_p} \right)^2 \quad (3.28)$$

where: $k_{hm} = k_{\text{granite}} = 0.003266 \text{ kW/m}\cdot\text{K} (2.81 \text{ kcal/(m}\cdot\text{hr}\cdot^\circ\text{C)})$

$k_{hp} = k_{\text{sandstone}} = 0.002077 \text{ kW/m}\cdot\text{K}$

$\rho_{cm} C_{cm} = 2.3824 \text{ kJ/kg}\cdot\text{K} (\text{granite cap block})$

$\rho_{cp} C_{cp} = 2.1803 \text{ kJ/kg}\cdot\text{K} (\text{sandstone cap block})$

$$\frac{L_p}{L_m} = 173.99 \quad (3.18)$$

In addition, the density/specific heat product for the cap rocks and reservoir matrices were assumed to be approximately equal:

$$\rho_{cm} C_{cm} = \rho_{cp} C_{cp} \text{ and } \rho_m C_m = \rho_p C_p \quad (3.29)$$

Therefore, the substitution of the variables into equation (3.28) yields

$$\frac{t_m}{t_p} = \left(\frac{0.002077 \text{ kW/m}\cdot\text{K}}{0.003266 \text{ kW/m}\cdot\text{K}} \right) \left(\frac{\rho_{cm} C_{cm}}{\rho_{cp} C_{cp}} \right) \left(\frac{1}{173.99} \right)^2 = 2.1007 \times 10^{-5}$$

Converting the dimensionless to a real time value leads to the final form of the ratio as shown below in equation (3.30):

$$\frac{t_m}{t_p} = 2.1007 \times 10^{-5} \times 365.25 \text{ D/yr} \times 24 \text{ hr/D} \times 60 \text{ min/hr}$$

$$\frac{t_m}{t_p} = 11.05 \text{ min/yr} \quad (3.30)$$

Flow Rate Scaling

Stegemeier et. al.⁹ used parameter (6) in Table 3.2 to scale the injection and production rates:

$$\frac{w_m}{w_p} = \left(\frac{\rho_{cm}}{\rho_{cp}} \right) \left(\frac{L_m}{L_p} \right)^3 \left(\frac{\phi_m \Delta S_m}{\phi_p \Delta S_p} \right) \left(\frac{t_p}{t_m} \right) \quad (3.31)$$

where: $\frac{L_p}{L_m} = 173.99 \quad (3.18)$

$$\gamma(\rho_r) = \frac{\rho_p}{\rho_m} = 0.9 \quad (3.20)$$

$$\frac{t_m}{t_p} = 2.1007 \times 10^{-5} \quad (3.29)$$

$$\phi_m = 0.321 \quad (\text{in accordance with the specifications of the Wygal particle distributor}) \quad (3.32)$$

$$\phi_p = 0.31 \quad (3.33)$$

$$\Delta S_m = 0.85 \quad (\text{scaling assumption}) \quad (3.34)$$

$$\Delta S_p = 1 - S_{or} - S_{wc} = 1 - 0.15 - 0.23 = 0.62 \quad (3.35)$$

Substitute identities (3.18), (3.29) and (3.31) to (3.34) into equation (3.30):

$$\frac{w_m}{w_p} = \left(\frac{1}{0.9} \right) \left(\frac{1}{173.99} \right)^3 \left(\frac{0.321 \times 0.85}{0.31 \times 0.625} \right) \left(\frac{1}{2.1007 \times 10^{-5}} \right) = 0.143 \times \frac{\left(\frac{10^6 \text{ cm}^3}{24 \text{ hr} / D \times 60 \text{ min} / \text{hr}} \right)}{\text{m}^3 / D}$$

which reduces to:

$$\frac{w_m}{w_p} = 9.8995 \frac{\text{cm}^3 / \text{min}}{\text{m}^3 / D} \quad (3.36)$$

Since the model simulates one quarter of the total prototype injection rate of $100 \text{ m}^3/D$, the total steam injection rate, q_{ism} , for this study was determined to be $247.49 \text{ cm}^3/\text{min}$ as follows:

$$q_{is_m} = \frac{1}{4} \times 100 \text{ m}^3 / \text{D} \times 9.8995 \frac{\text{cm}^3 / \text{min}}{\text{m}^3 / \text{D}} = 247.49 \text{ cm}^3 / \text{min}$$

Scaling of Steam Quality

When using parameter (2) in Table 3.2 to determine the model steam quality, Stegemeier et. al.⁹ assumed that cap and base rock heat predominates, which is often the case in steam drive processes in thin reservoirs, so $A^* = \phi_R S_R (\rho_R C_R / \rho_{cR} C_{cR})$:

$$f_{sm} = \left(\frac{C_w \Delta T}{L_v} \right)_m \left\{ \left(\frac{f_i L_v}{C_w \Delta T} + 1 \right)_p \times \left[\left(\frac{\phi_p \Delta S_p}{\phi_m \Delta S_m} \right) \left(\frac{\rho_p C_p}{\rho_m C_m} \right) \left(\frac{\rho_{cm} C_{cm}}{\rho_{cp} C_{cp}} \right) \right] - 1 \right\} \quad (3.37)$$

The model steam quality was then calculated for all corresponding pressures in Table 3.3 using the constants as already described in (3.29), (3.31) to (3.34) with $f_s = 0.70$ for the prototype.

Example 3.1:

All the sample calculations, unless otherwise specified, were calculated for the last row of data in Table 3.3 corresponding $p_p = 0.345 \text{ MPa}$ (50 psia) and $p_m = 0.006895 \text{ MPa}$ (1 psia).

$$f_{sm} = \left(\frac{148.53 \text{ kJ / kg}}{2410.39 \text{ kJ / kg}} \right)_m \left\{ \left(\frac{0.7 \times 2149.7 \text{ kJ / kg}}{485.48 \text{ kJ / kg}} + 1 \right)_p \times \left[\left(\frac{0.31 \times 0.62}{0.321 \times 0.85} \right) (1)(1) \right] - 1 \right\} = 0.1163$$

To complete the scaling of steam quality, the proportions of injected water (w_a) and superheated steam (w_{ss}) were calculated. The quality and hence, water proportions was a function of the enthalpy of steam from the steam generator at 120°C, the temperature of the quality control feed water (generally taken at the room temperature at 23°C) and the heat loss from the metal lines. The heat balance equated the enthalpy rate of the two inlet water streams mixed together ($w_{wt} = w_a + w_{ss}$) to the enthalpy rate of wet steam injected into the

model plus the heat losses. In this study, the heat loss (q_h) was assumed to be zero so the final equation was written as:

$$\frac{w_s}{w_{wt}} = \frac{w_s}{w_s + w_m} = \frac{h_m - f_s L_v - C_w \Delta T - q_h / w_{wt}}{h_m - h_{wa}} \quad (3.38)$$

Example 3.2:

$$\frac{w_s}{w_{wt}} = \frac{2725.5 \text{ kJ/kg} - (0.1163 \times 2410.39 \text{ kJ/kg}) - 148.53 \text{ kJ/kg} - 0}{2725.5 \text{ kJ/kg} - 96.518 \text{ kJ/kg}} = 0.8736$$

Scaling of Model Oil Viscosity

Because of the significance of scaling the oil production after steam breakthrough by matching the pressure gradient in the steam zone and oil, the oil viscosity was scaled according to parameter (3) in Table 3.2:

$$\frac{\mu_{om}}{\mu_{op}} = \left(\frac{f_{sm}}{f_{sp}} \right) \left(\frac{\mu_{sm}}{\mu_{sp}} \right) \left(\frac{\rho_{sp}}{\rho_{sm}} \right) \left(\frac{\rho_{om}}{\rho_{op}} \right) \quad (3.39)$$

Example 3.3:

Substituting the data from Table 3.3 and identities $f_s = 0.70$ and (3.20) into equation (3.39) yields:

$$\frac{\mu_{om}}{\mu_{op}} = \left(\frac{0.116}{0.70} \right) \left(\frac{0.0102}{0.0138} \right) \left(\frac{0.532}{0.046} \right) \left(\frac{1}{0.9} \right) = 1.60$$

Scaling of Model Permeability

Stegemeier et. al.⁹ scaled the model permeability using parameter (5) in Table 3.2:

$$\frac{k_m}{k_p} = \left(\frac{\phi_m \Delta S_m}{\phi_p \Delta S_p} \right) \left(\frac{L_m}{L_p} \right) \left(\frac{\mu_m}{\mu_p} \right) \left(\frac{\rho_{op}}{\rho_{om}} \right) \left(\frac{t_p}{t_m} \right) \quad (3.40)$$

It can be noted from equation (3.35) that k_m/k_p is temperature dependent since μ_m/μ_p is a function of temperature. However, k_m/k_p cannot be a function of temperature, a single representative value of μ_m/μ_p must be selected in order to determine a single quantity for

the model permeability. As previously noted, the μ_m/μ_p ratio is significant only when steam pressures are low which occurs after steam breakthrough and around the vicinity of the production well. Consequently, Stegemeier et. al.⁹ suggested that the lower portion of Table 3.3 should be weighted heavily. Substituting an average value of μ_m/μ_p taken at a 1.00 MPa prototype pressure as well as the constants defined as (3.18), (3.20), (3.29), (3.32) to (3.35), the model permeability was calculated to be:

$$\frac{k_m}{k_p} = \left(\frac{0.321 \times 0.85}{0.31 \times 0.62} \right) \left(\frac{1}{173.99} \right) (7.71)(0.9) \left(\frac{1}{2.1007 \times 10^{-5}} \right) = 2695.08$$

Since the permeability of the prototype, k_p , is 2 darcies,

$$k_m = k_p \times 2695.08 = 2 \text{ darcies} \times 2695.08$$

Thus, $k_m = 5390.17$ darcies (3.41)

Scaling of Vertical Wells

As a result of the small size of the model with a length scale of 173.99 and the large size of the glass beads, it was impractical to directly geometrically scale the vertical wells. This was primarily due to the mechanical problems encountered in constructing a small diameter well as well as the probability that the well size would lose significance when the diameter of the beads in the porous media approached or exceeded the model diameter. Stegemeier et. al. introduced the 'slit' well concept where the effective radius of the slit was a function of the bead pack arrangement in front of the slit and the slit width, ω :

$$\omega = 2\pi r_m \tag{3.41}$$

where ω = slit width and r_m = the effective radius of the model well.

In this study, it was assumed that the diameter of the prototype well was 6 inches. Using this assumption and substituting it into equation (3.18), the model well with was determined to be 0.108" as described below:

$$L_m = \frac{L_p}{173.99} = \frac{6''}{173.99} = 0.0345'' = d_m$$

Thus, since the model well radius is $r_m = 0.01725''$, the slit width was calculated from equation (3.37):

$$\omega = 2\pi(0.01725'') = 0.108'' \quad (3.43)$$

Table 3.4 summarizes the scaling set used for the Aberfeldy model.

Table 3.4: Scaling Set for Steam Processes

Length Scale: $\frac{L_p}{L_m} = \gamma(L) = 173.99$ (3.18)

Pressure Relation: $p_m = 0.004692 + 0.006386p$ (3.24)

Temperature Relation: $T_m = 0.286T_p - 3.65$ (3.27)

Time Scale: $\frac{t_m}{t_p} = 11.05 \text{ min / yr}$ (3.30)

Steam Quality:
$$f_m = \left(\frac{C_w \Delta T}{L_v} \right)_m \left\{ \left(\frac{f_s L_v}{C_w \Delta T} + 1 \right)_p \times \left[\left(\frac{\phi_p \Delta S_p}{\phi_m \Delta S_m} \right) \left(\frac{\rho_p C_p}{\rho_m C_m} \right) \left(\frac{\rho_{cm} C_{cm}}{\rho_{cp} C_{cp}} \right) \right] - 1 \right\}$$
 (3.32)

Viscosity Ratio:
$$\frac{w_s}{w_{wt}} = \frac{w_s}{w_s + w_{ss}} = \frac{h_{ss} - f_s L_v - C_w \Delta T - q_h / w_{wt}}{h_{ss} - h_{ws}}$$
 (3.33)

$$\frac{\mu_{cm}}{\mu_{cp}} = \left(\frac{f_m}{f_{sm}} \right) \left(\frac{\mu_{sm}}{\mu_{sp}} \right) \left(\frac{\rho_{sp}}{\rho_{sm}} \right) \left(\frac{\rho_{cm}}{\rho_{cp}} \right)$$
 (3.34)

Injection and Production Rates: $\frac{w_m}{w_p} = 9.8995 \frac{\text{cm}^3 / \text{min}}{\text{m}^3 / \text{D}}$ (3.36)

Permeability $k_m = 5390.17 \text{ darcies}$ (3.41)

Slit Width $\omega = 0.108''$ (3.43)

Chapter 4

Experimental Apparatus and Procedure

The following chapter describes the apparatus, materials and procedures used in this study. This section summarizes the experimental procedures, such as packing and fluid saturation, used when preparing and operating homogeneous, bottom water and gas injection models. Appendix C, a supplement to this section, provides detailed information pertaining to the laboratory apparatus and procedures.

Experimental Apparatus

The apparatus used in the study was comprised of the following essential components: the model cart and rail system, solvent and steam injection equipment, produced fluids collection unit, and cold storage component. Figure 4.1 is a schematic illustration of the scaled physical model and its accompanying equipment. Plate 4.1 and 4.2 present an overall view of the experimental apparatus including the cap and base rocks clamped in place on the scaled physical model.

Physical Model

The model used in this study was designed to represent one-quarter of an eight hectare (20 acre) five spot pattern having the dimensions of 281.55 m x 281.55 m x 11 m (thick) in the Aberfeldy heavy oil reservoir. Plate 4.3 is a photograph of the scaled physical model, which was a custom built fibreglass tray filled with glass beads that simulated the porous medium. Four slit wells were constructed, according to Stegemeier, Laumbach and Volek's description of scaled vertical wells, in each corner of the fibreglass model. Granite blocks were placed above and below the model to act as the overburden and underburden.

Because the model was to be designed with the length scale factor of 173.2, the fibreglass tray was constructed with the dimensions of 81.28 cm (32 in) x 81.28 cm (32 in) x 6.35 cm (2.5 in thick). In order to satisfy the low pressure scaling criteria, the

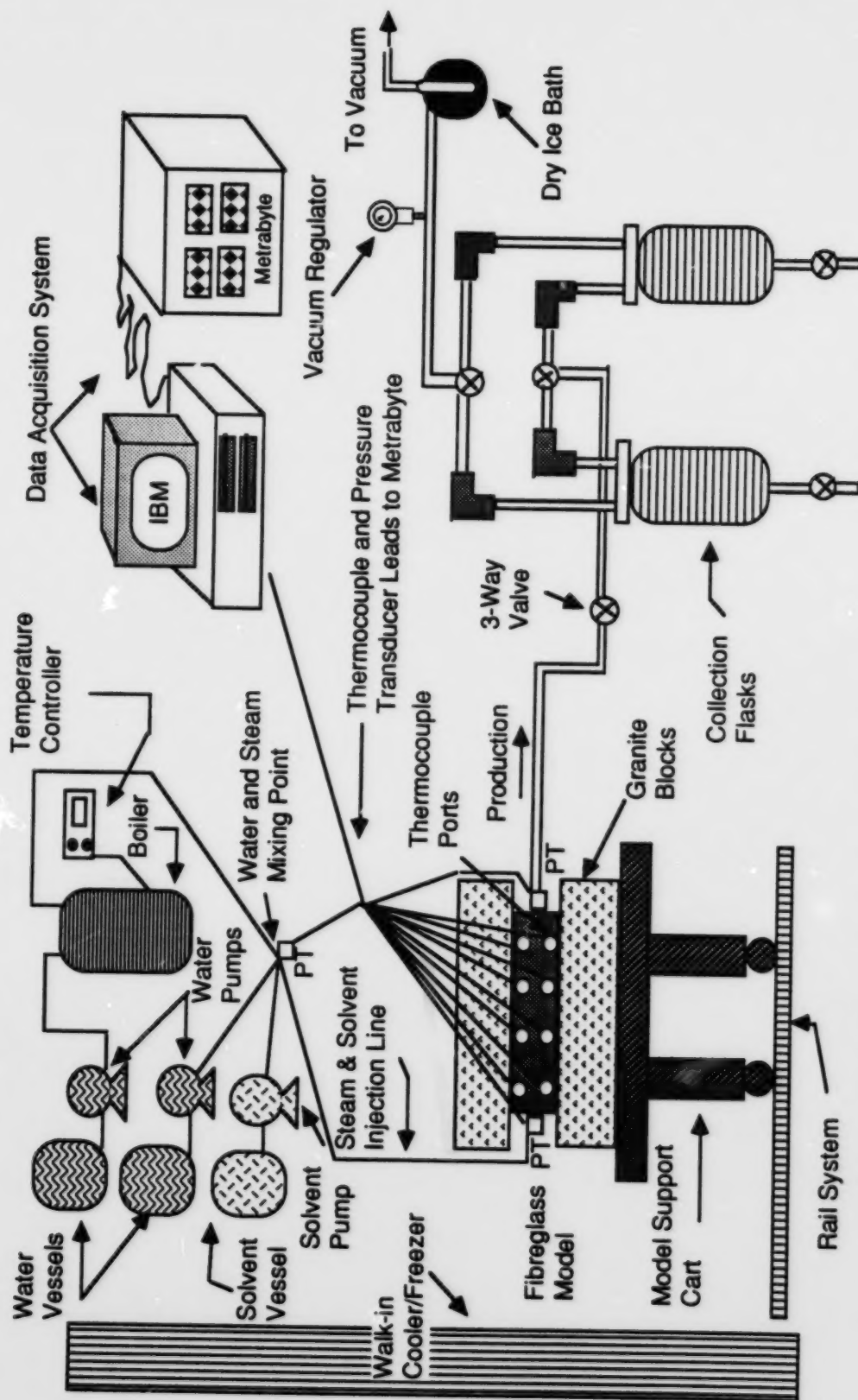


Figure 4.1: Schematic Diagram of Apparatus

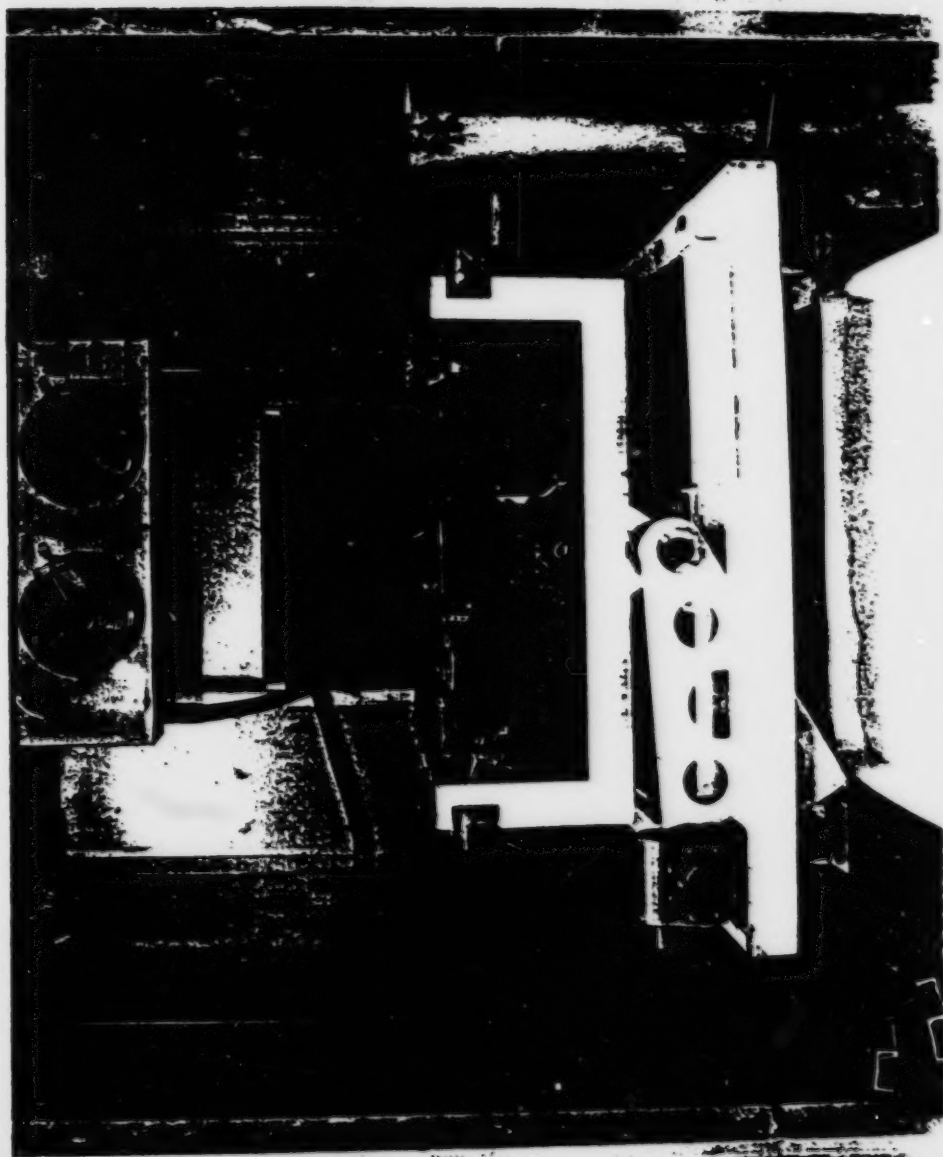


Plate 4.1 Overall View of Low Pressure Apparatus.

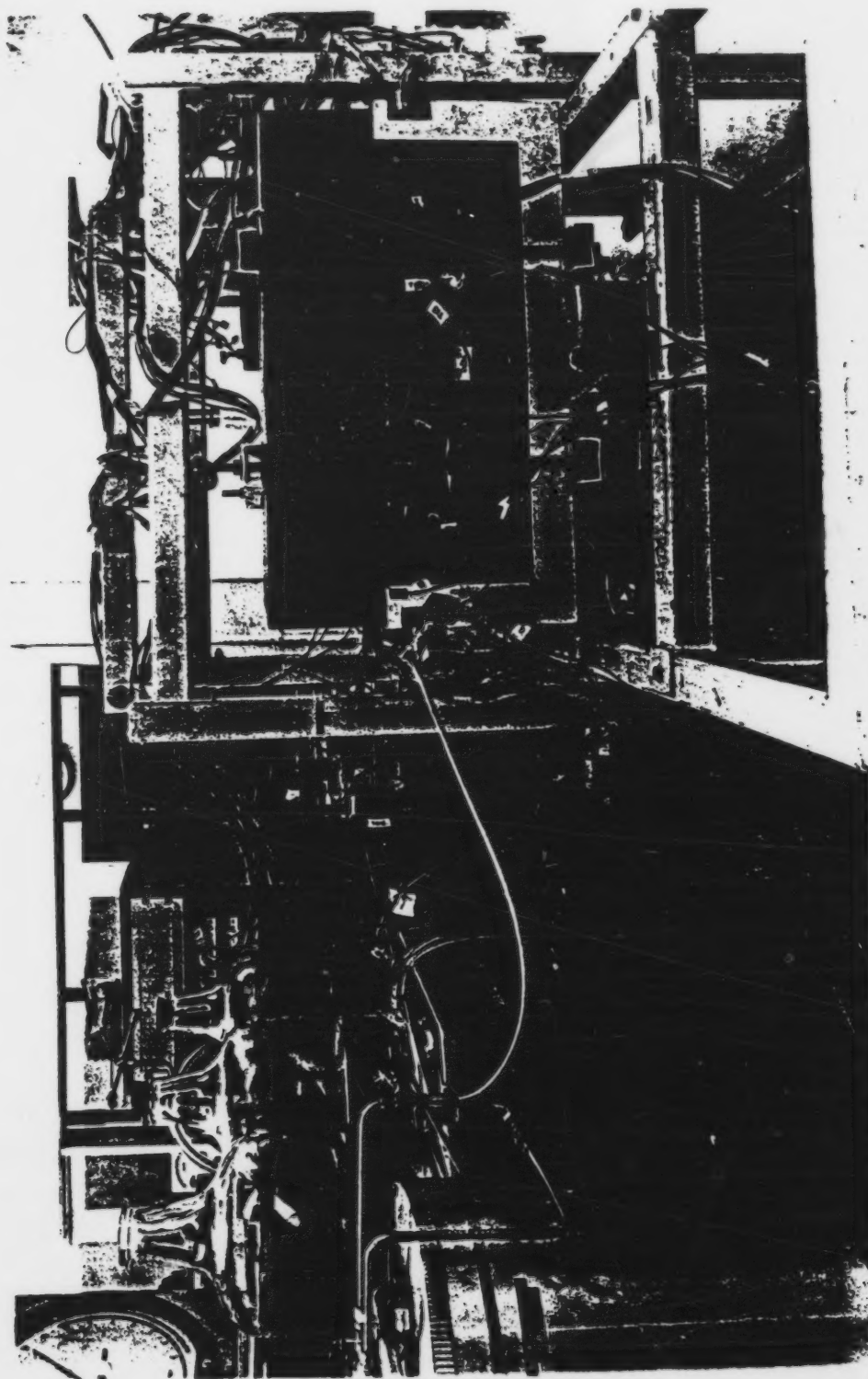


Plate 4.2 View of Model in Operating Position.

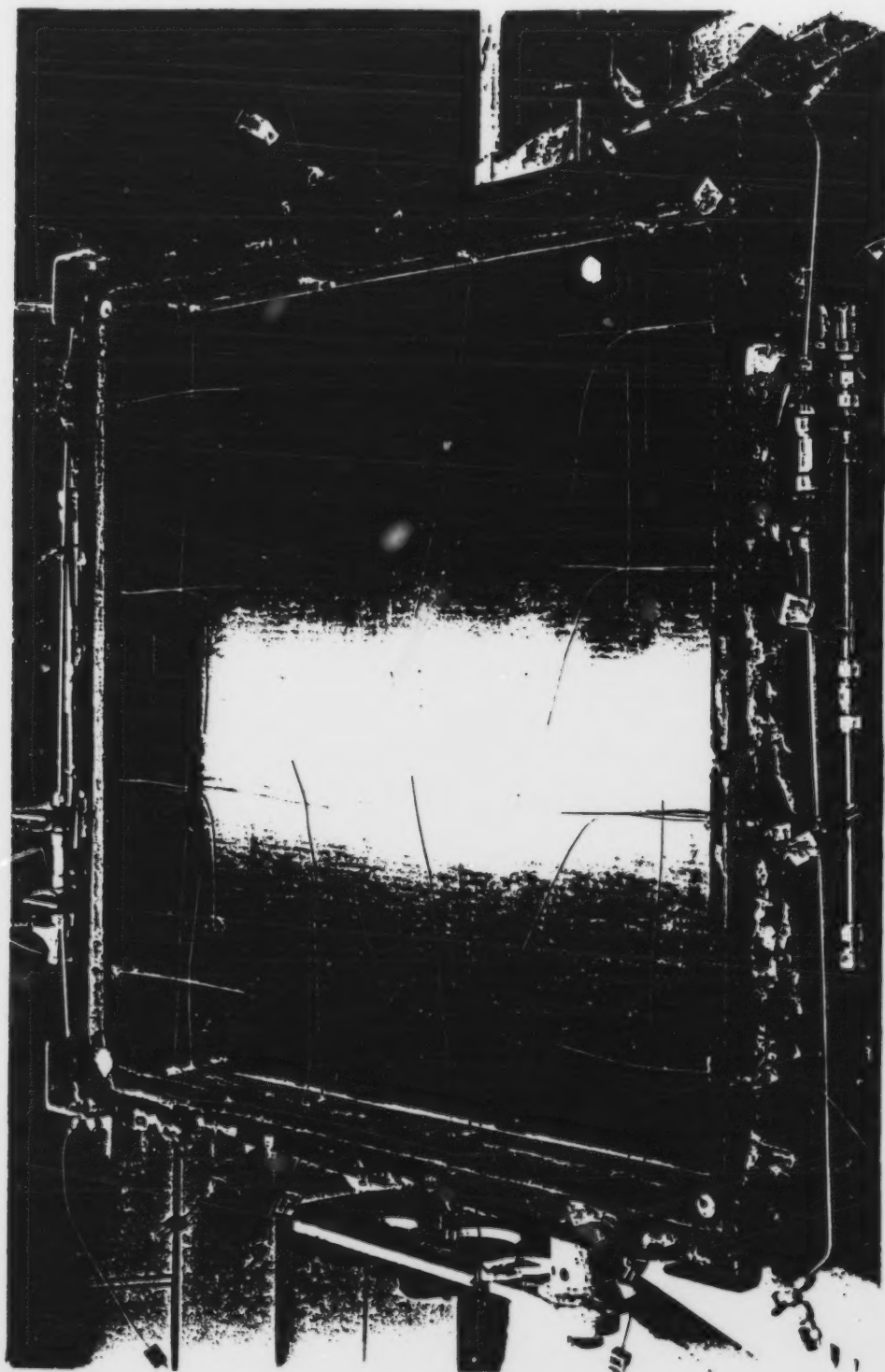


Plate 4.3 Top View of the Scaled Physical Model.

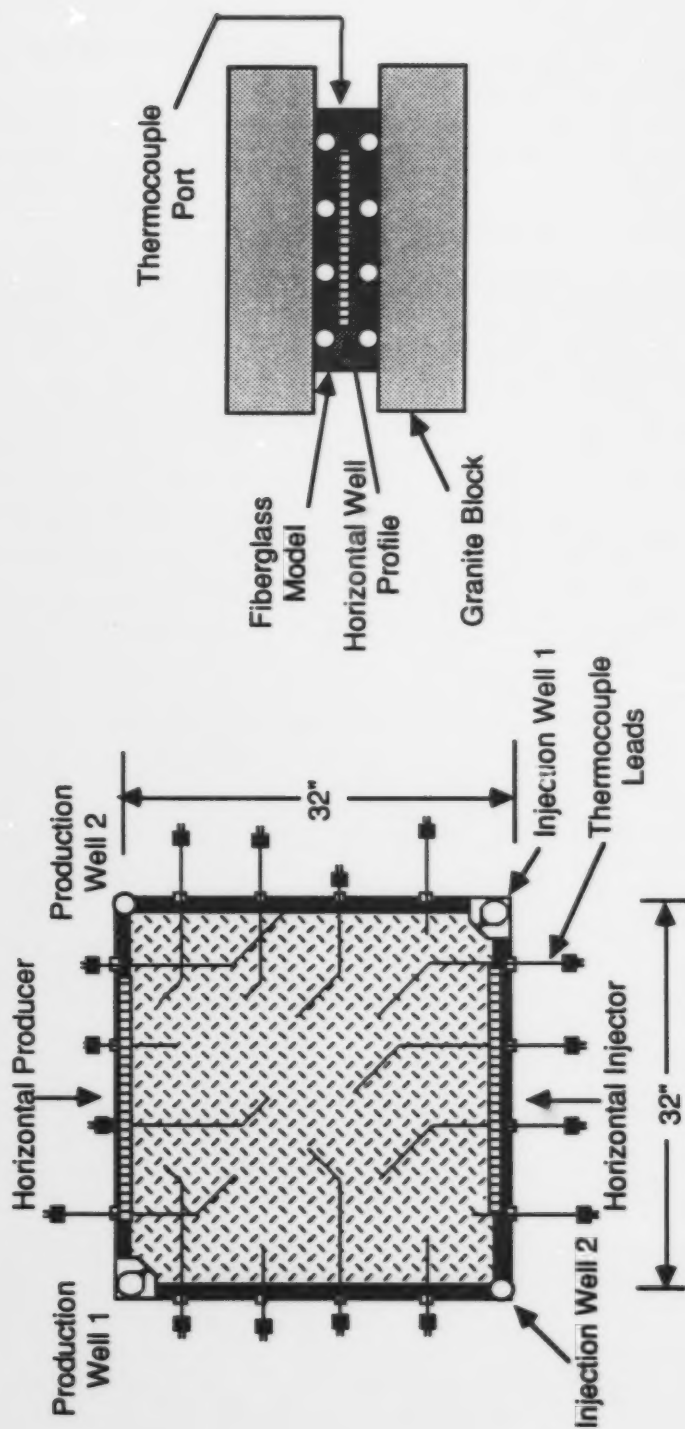
experiments were performed under vacuum conditions which involved applying severe loads over a large surface area. Therefore, it was required to select a material with a low heat transfer coefficient that could withstand a high degree of loading. Fibreglass was selected as the model material since it not only satisfied the conditions, but was also inexpensive and relatively easy material to machine.

The cap and base rocks of the model were made of two granite blocks each weighing 2000 pounds and having the dimensions of 91.4 cm (36 in) x 91.4 cm (36 in) x 21.6 cm (8.5 in thick). These blocks were used to simulate the heat transfer characteristics of the overburden and underburden of the Aberfeldy reservoir. The sides of the fibreglass tray were covered with cellular Neoprene to minimize heat loss from the lateral "no flow" boundaries of the model.

Vertical and Horizontal Wells

Figure 4.2 shows the detailed internal features of the model, including the location of temperature sensors and well positions. Scaled aluminum slit wells were machined in each corner of the model to simulate vertical wells. The effective radius of the slit well was a function of the slit width and the arrangement of the bead pack directly in front of the slit. In addition, the wells were designed to permit the insertion of a gate device which would enable the preferential selection of injection and production intervals.

Horizontal wells were represented by perforations machined into two sides of the model. Each well was 16 inches in length and located between two vertical wells on each side of the model. Because the wells were unscaled, they did not consider skin factor or pressure transient behaviour within the horizontal wellbore. However, they were designed to meet the material balance specification by considering constant injection and production rates, such that the total flow capacity of one horizontal well was equivalent to that of its scaled vertical counterpart.



Top View

This view illustrates the approximate positions of the top thermocouple layer and the two horizontal wells as defined by a series of perforations along the side of the model.

Side View

This view shows the relative position of the upper and lower thermocouples and horizontal well.

Figure 4.2: Schematic Diagram of Thermocouple Positions

Porous Media

In order obtain a model permeability of 4200 darcies and hence, satisfy the scaling criteria, a glass bead pack having an average bead diameter of 3 mm (6-8 U.S. mesh) was selected as the porous media. However, due to the high purchase cost of glass beads, they were cleaned and dried after each experiment so that they could be reused for future runs. The beads can be seen in their containment unit in Plate 4.1.

Model Cart, Rail System and Cold Storage Compartment

A cold storage compartment was built to enable the model to be cooled to an initial temperature of 3°C that was required to fulfill the model temperature scaling criteria. As an adjunct, the cooler was converted to a freezer to permit the creation of bottom water. The custom built walk-in cooler/freezer had the dimensions of 8 ft x 10 ft x 7 ft and is shown in Plate 4.1 along with the Wygal Particle Distributor, glass beads, and bead drier.

The entire model, including the two granite blocks, rested on top of a support cart which was set on castors. This facilitated the movement of the model which was rolled in and out of the cold storage compartment on the accompanying tracks. The upper granite block was placed on top of the fibreglass tray with a hydraulic hoist system. A shaft, connecting the rack and pinion system to a gear box, was welded to the support cart. The gear box was used to tilt the 4000 pound model to a maximum angle of 45° with respect to the horizontal. Tilting the frame and saturating from the downdip end increased process efficiency by generating a gravity stabilized front. Furthermore, dipping reservoirs could be simulated using the existing equipment.

Fluid Injection System

The steam injection equipment consisted of two Milroy controlled volume pumps and a low pressure boiler. To generate the desired steam quality, it was necessary to mix a stream of superheated steam with one of room temperature water. One of the Milroy

pumps transported de-aired room temperature distilled water to the water-steam mixing point while the other pumped superheated steam generated from the boiler. The boiler electrically heated room temperature feed water to superheated steam and was comprised of an oil bath with a seven heating rods and 80 m (24.38 m) of 1/4" diameter stainless tubing coiled inside the unit which can be seen in Plate 4.4. The boiler coil was divided into two subcoils each 40 m length—the inner coil pre-heated the water and the outer one converted the water to superheated steam.

Solvent was injected into the model by a Milroy pump at a rate of 200 cc/min. It was hoped that the relatively high injection rate would create a more distinct and extensive solvent channelling effect into the oil zone, which in turn, would provide a more conductive path for the steam to travel within the oil zone.

Fluid Collection System

The collection system, shown in Figure 4.3 and Plate 4.5, was developed to enable a single operator to extract large instantaneous samples of produced fluids without assistance. The unit consisted of a hydraulic pump, a mercury manometer, two plastic vacuum trap collection containers each equipped with a chilling coil and a fluid level indicator tube, a circulating pump for the condenser coolant, an air inlet pressurized discharge, a vacuum in order to evacuate the container, and a dry ice bath.

Although each vacuum trap was capable of collecting a maximum sample sizes of 4000 cc, 2000 cc samples were taken using 2000 cc graduated cylinders to generate more data specimens for the experimental analysis. A hydraulic suction pump was used to generate a vacuum and hence, extract the samples. Under standard experimental conditions, it maintained a constant vacuum of 68 cm of mercury for a fully evacuated system. The vacuum was monitored during the run by an adjoining mercury manometer.

Since the traps were opaque and the samples were produced as a frothy mixture, it was impossible to monitor the volume of production using an electrical sensor unit. Clear

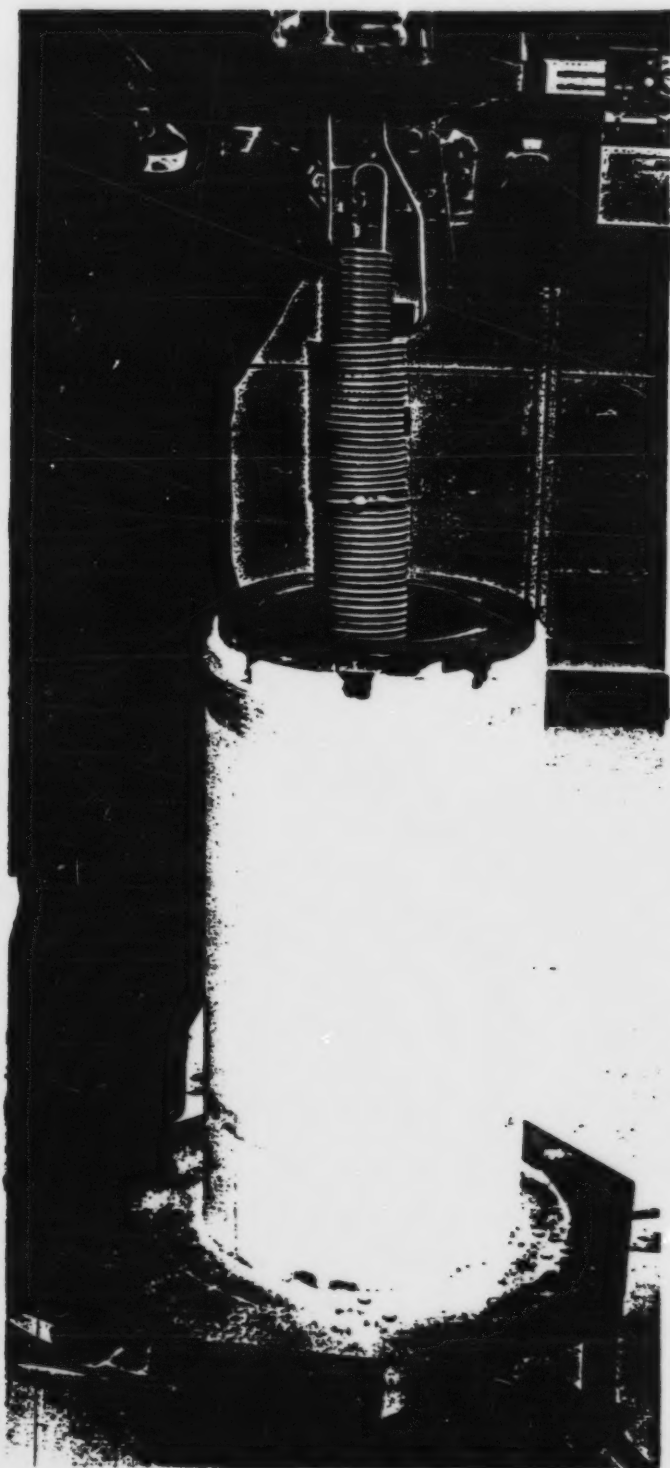


Plate 4.4 Internal View of the Scaled Physical Model.

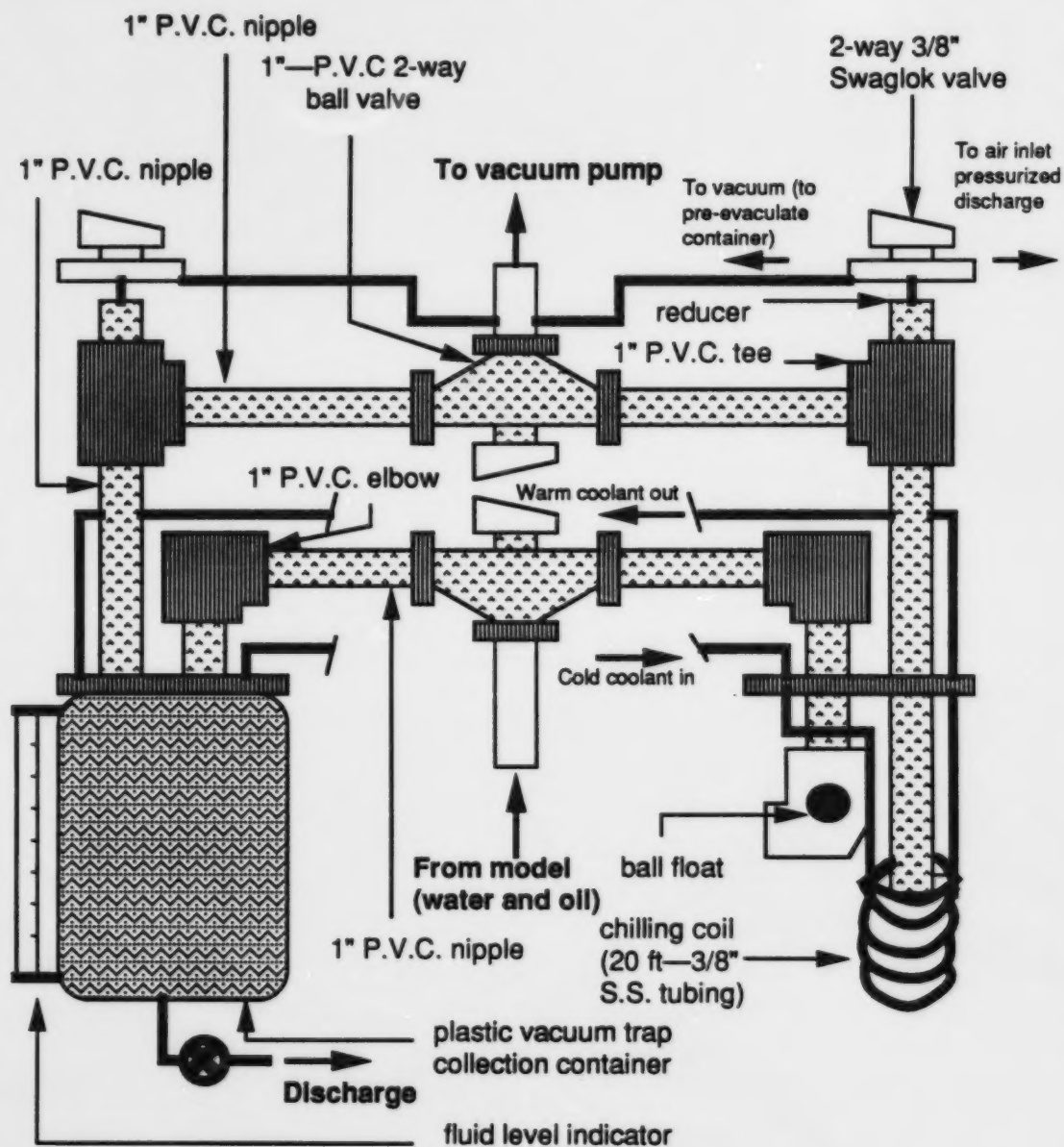


Figure 4.3: A schematic diagram of the produced fluid collection system

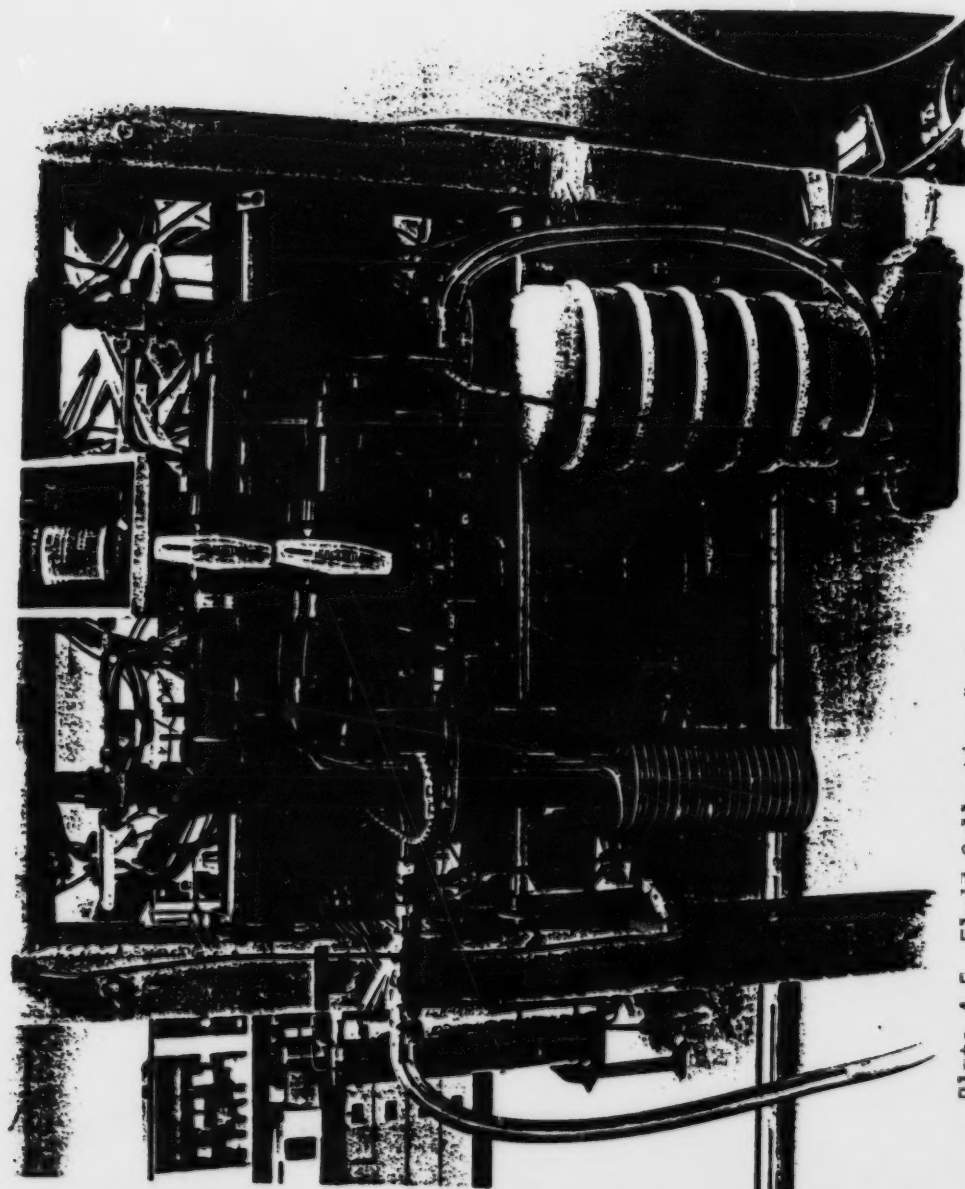


Plate 4.5 Fluid Collection System.

vacuum tubing was used to visually monitor the fluid level in each cylinder and hence, the quantity of production. Under low pressure vacuum conditions, it was believed that some vaporization of produced fluids would occur. Thus, chilling coils consisting of 20 ft of 3/8" Stainless Steel tubing were installed in each trap to recirculate antifreeze coolant, with the aid of a circulating pump. The coils were used in order inhibit the vaporization of produced samples and were built inside the containers.

The flasks were designed to enable each flask to operate independently of the other. Because the high viscosity of the hydrocarbon in the initial phase of the experiment, an air inlet pressurized discharge was built into each flask. The purpose of this inlet was to inject approximately 1 psi of air into the container to shorten the length of time required to drain each collection container. If more than 1 psi was injected, it would propel the plastic container away from the plastic fittings and valves. Thus, a flexible cable was added to enclose the entire containment unit (plastic container, fitting and valves) as a safety precaution. To maintain a vacuum, each container was pre-evacuated using the negative pressure outlet prior to sample collection by turning the 2-way valve towards the vacuum source. Finally, a carbon dioxide dry bath was installed at the downstream of the collection unit to gather any produced vapours that had passed through the condensers in the flasks.

Data Acquisition System

An extensive data acquisition network consisting of thirty-seven thermocouple channels and four pressure transducers was installed at optimum locations within the fibreglass model. The model was machined to permit a maximum of thirty-two type-J thermocouples to be strategically installed in two layers inside the model, with sixteen in each layer. In addition, five type-J thermocouples were used to measure the injection and production temperatures at various locations as well as the temperature of the mixing point. However, because these points of injection and production are situated close to metal fittings and connection, ungrounded thermocouples were chosen instead to prevent any

grounding effects from occurring. The transducers were placed adjacent to each well in order to monitor the inlet and outlet pressures.

During the course of this study, three data acquisition systems were used to collect and process the experimental data with the aid of an IBM PC: Megadac 2000, Process I/O System and Metrabyte. Megadac was succeeded by the Process I.O which in turn was replaced by the Metrabyte system which was used for the majority of the experiments. More detailed information regarding the operation and installment of Megadac and Metrabyte are provided in Appendix C.

The Megadac 2000 data acquisition unit had the potential to monitor 128 input channels as quickly as 2000 samples per second or as slowly as one sample per second. In all the experiments, the scan time was set as one scan every thirty seconds. The Megadac 2000 data acquisition system broke down prior to the initiation of Run 70B. Because of the high repair cost and extensive amount of repairs needed for the Megadac unit as well as the modifications required for the Megadac software package, Optim Users Software, it was decided to select another acquisition system.

The new system was developed by the the Department of Chemical Engineering at the University of Alberta and was modified specifically for the purposes of this research project. The *Process I/O System* is based on a Digital Equipment Corporation (DEC) LSI 11/03 microcomputer using an Adac Corporation Model 1113AD with 2 Model 1113EX boards to provide low level analog input. Thirty two channels of input were available, configured as thermocouple type input or ± 100 millivolt input. If a channel was configured as a thermocouple type, cold junction compensation is performed on the board.

The I/O operating system used on the LSI 11/03 was the DEC RT11 system. The program to perform the input and prepare the data for storage on an IBM PC was written in Parallel Pascal which was a product from Interactive Technology Incorporated. The program used to receive the data from the LSI 11/03 is written under DOS in Modula-2 in the version of the M2SDS development system. This system was chosen because

equipment repairs and software revision could be performed quickly at the University of Alberta whereas the only place to service the Megadac 2000 is in Maryland, U.S.A. Furthermore, the new system could be adapted to the existing IBM personal computer in the laboratory with a series thermocouple jack panels built to satisfy the total number of thermocouple inputs.

Based on the results from 70B, the Process I/O system was assessed to be a poor replacement for the old Megadac data acquisition unit. It was discovered shortly after the installation of the system that it was inflexible to any alterations. Each time slight modifications to the equipment were implemented, such as the addition of another thermocouple lead, the data collection program had to be completely rewritten in Modula. Furthermore, the Process I/O lacked expansion capability since it could only read 32 thermocouple temperature values simultaneously. It was unable to handle any more input channels for future experiments, such as heat flux transducers or additional thermocouples or other modifications to the system. The other flaws regarding this unit were that it was undependable, since it ran on an eight inch and obsolete computer unit which had to be replaced twice in the duration of the run and the questionable "black box" calculations used to process and generate the data. Therefore, it was returned to the unit at the end of the trial period due to the complete lack of experimental confidence in the Process I/O System.

After investigating other data acquisition units including a Macintosh computer package, it was decided to purchase a DAS-8 board, four EXP-16 multiplexers and the Labtech Notebook Software from the Metrabyte Corporation. The advantages of this system was its versatility, expansion capability, equipment repair accessibility and the supplemental software package. Labtech Notebook package processed all raw thermocouple (mV) and pressure transducer (mV) measurements and converted them into real values of temperature and pressure ($^{\circ}\text{C}$ and kPa) and time (seconds). Because the experimental data was stored in ASCII file format, it could be analyzed in a spreadsheet program, such as Lotus 1-2-3 or Symphony, directly through Labtech Notebook.

Model Fluids

Selection of Model Oil for the Aberfeldy Reservoir

Choosing the upper limit values of the viscosity relationships between the model oil and the Aberfeldy prototype oil as previously stated in Table 3.3 in Chapter 4, an average ratio of model oil viscosity to prototype oil viscosity (μ_{oM}/μ_{oP}) was determined to be 7.26. The ideal viscosity of the model oil was then calculated at different model temperatures using both the viscosity and the temperature relationship between the model and prototype in equation 3.6 and is shown in Table 4.1.

Table 4.1: Temperature versus oil viscosity data for prototype and ideal model oil.

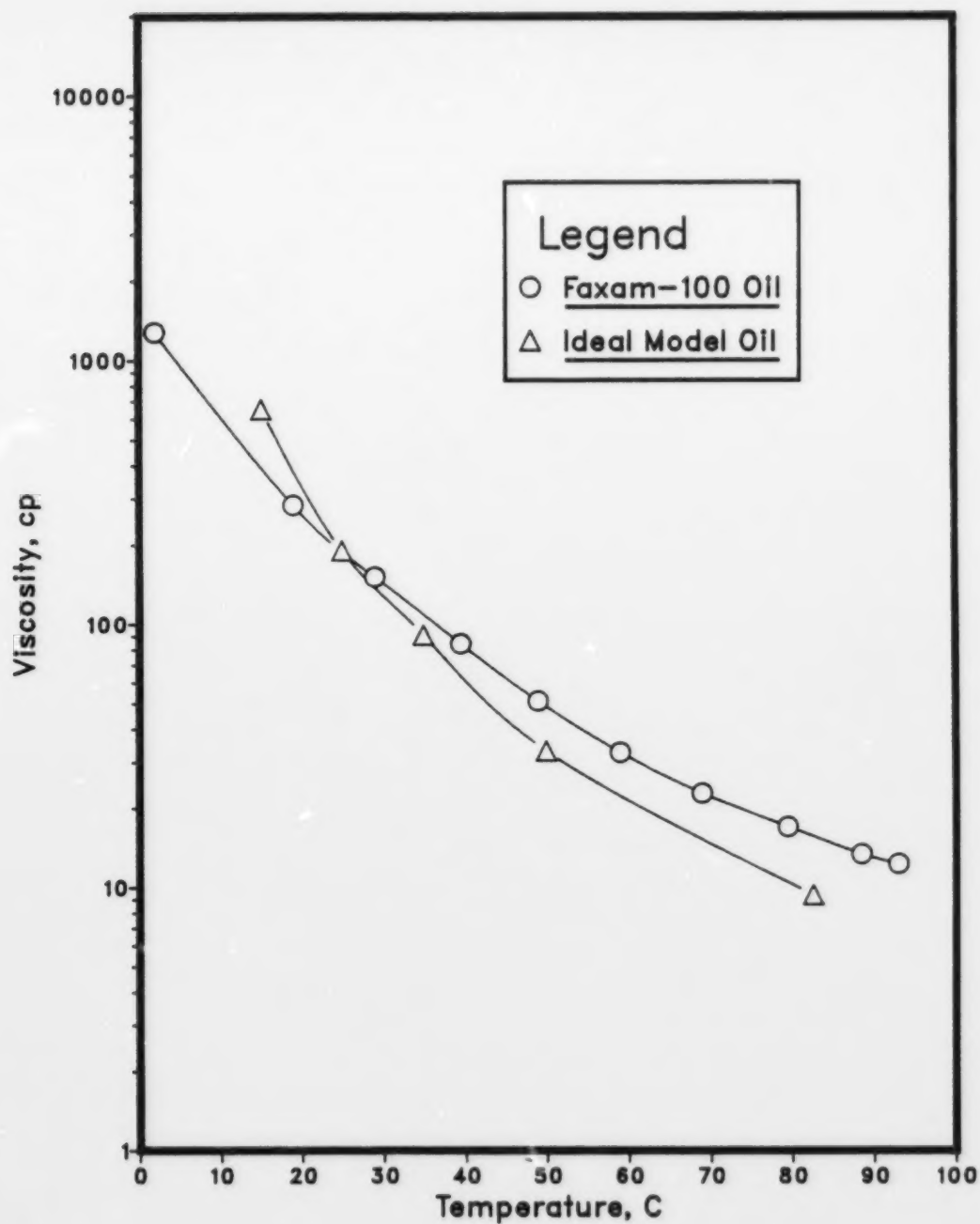
<u>Prototype Temperature (°C)</u>	<u>Prototype Oil Viscosity (mPa·s)</u>	<u>Model Temperature (°C)</u>	<u>Ideal Model Oil Viscosity (mPa·s)</u>
23.9	1275	3.2	9256.5
32.2	560	5.6	4065.6
65.6	90	15.1	653.4
135.0	12.5	35.0	90.75
301.7	1.29	82.6	9.37

Figure 4.4 is a viscosity-temperature profile plot of the refined MCT 30 base oil called Faxam-100, which was selected for as the actual model oil. Faxam-100 was chosen because its curve best matched that for the ideal Aberfeldy oil.

Solvent Selection

Following an extensive viscosity investigation, Heavy Virgin Naphtha solvent (HVN) was selected for the steamflood investigations conducted in the low pressure model. The chemical properties of the Heavy Virgin Naphtha, primarily the initial boiling point which was 61.0°C, caused the partial vaporization of the solvent to occur during the steamflood process which had an average upper temperature range of 80° to 100°C. This

Figure 4.4: Viscosity versus temperature profiles for the ideal model and actual selected (Faxam-100) model oil



phenomenon produced favourable results since the partial vaporization of the Heavy Virgin Naphtha further enhanced the mobilization of the oil as a consequence of the diffusion of the solvent vapour into the oil ahead of the solvent bank.

Figure 4.5 is a plot of viscosity versus HVN solvent concentration. Other properties of Heavy Virgin Naphtha are:

$$\rho_{\text{HVN}} = 0.7320 \text{ g/cc}$$

$$\text{API gravity} = 61.7418^\circ \text{ API}$$

$$\text{Initial Boiling Point} = 61^\circ\text{C}$$

$$\text{Final Boiling Point} = 131.5^\circ\text{C}$$

Preparation of the Experimental Model

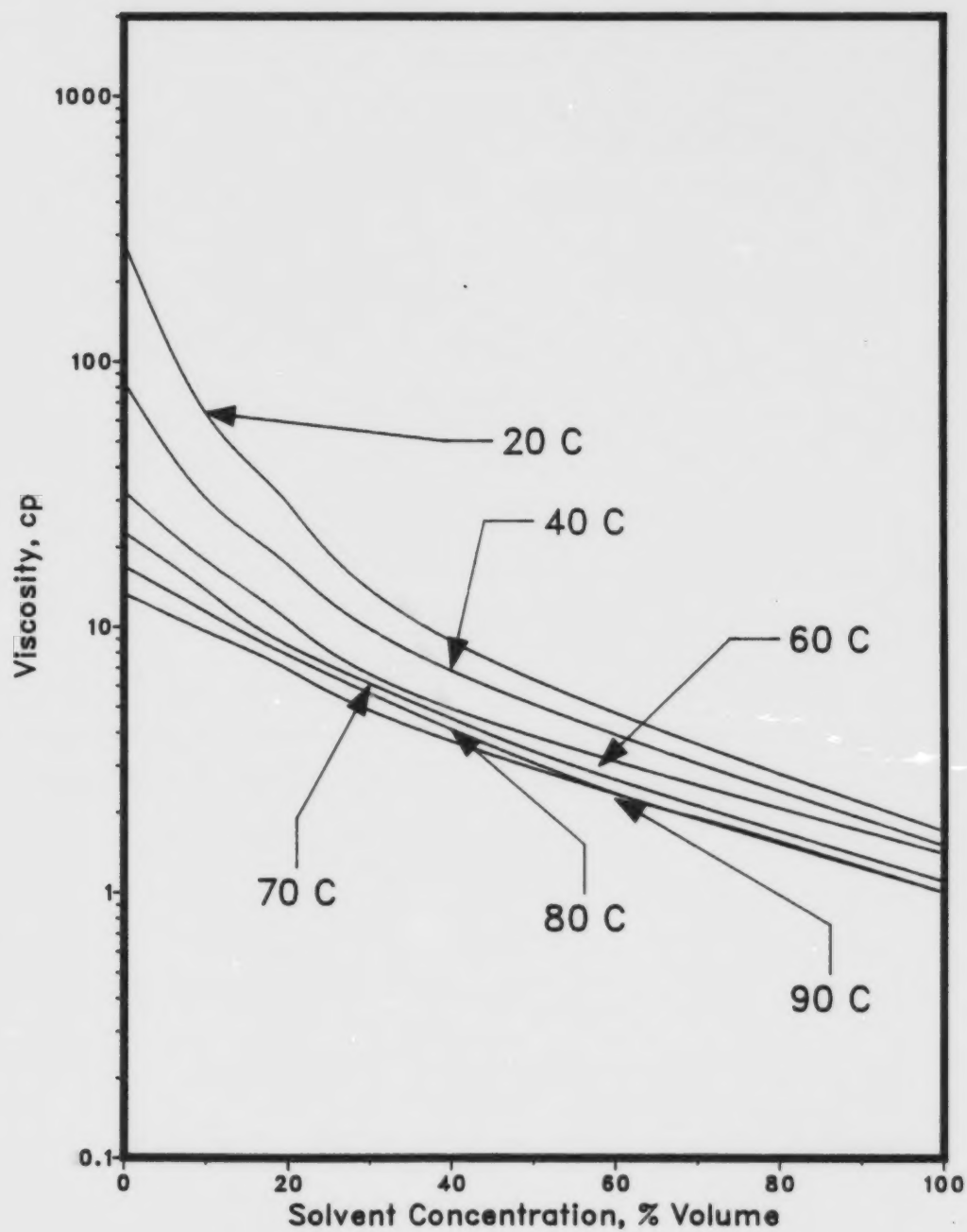
Model Packing Procedure

A "particle distributor" was used to pack the model with glass beads since traditional tamping and vibrating methods were not feasible for the large irregularly shaped fibreglass model. The concept of a distributor matrix was first introduced by Currie and Gregory (Wygol) and was later modified by Wygal. Whereas tamping and vibrating procedures were said to generate non-uniform or unstable particle packs, the particle distributor produced mechanically stable packs with uniform properties throughout that could be accurately reproduced.

The success of the particle distributor occurred as a result of the hitting action of the beads falling onto the pack surface. It was observed that the beads strike the pack singly after being distributed through a series of sieves. Part of their kinetic energy was transferred to the surface beads which were thereby knocked into more stable positions. As the bead pack grew, Wygal said that the surface appeared to be fluid and alive for a depth of two or three particle diameters.

Figure 4.6 is a schematic diagram of the Wygal particle distributor constructed for this study. It consisted of a 32"x32"x26" plywood frame, a metering board and a five wire

Figure 4.5: Viscosity of the mixture of Faxam-100 and Heavy Virgin Naphtha versus HVN solvent concentration



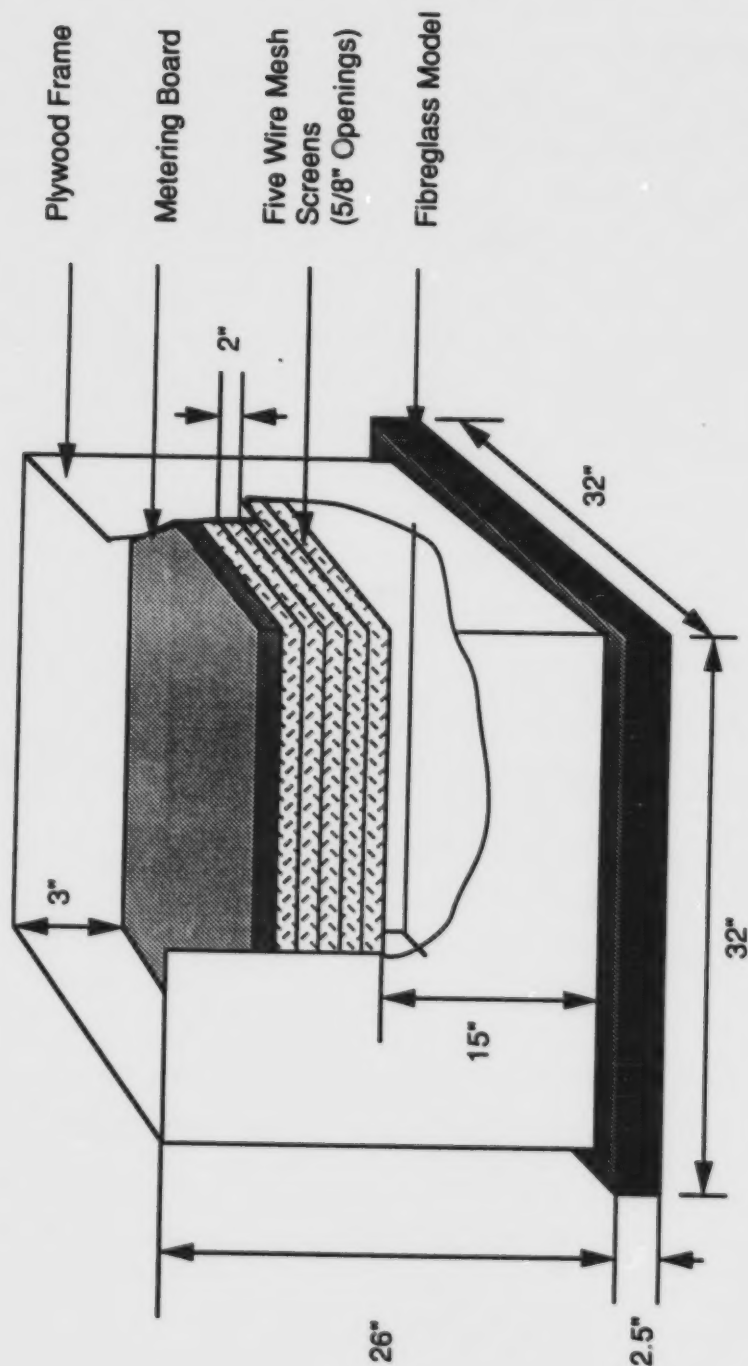


Figure 4.6: The Wygal Particle Distributor

mesh screens each with 5/8" openings that were offset from each other. The model was packed by supplying a continuous supply of the glass beads at a constant rate to the orifices on the metering board until the model was filled. The particle distributor was removed and any excess beads were trimmed off the model surface. Average model porosities ranged from 32% for a homogeneous model to 35% for a bottom water model, which was partially packed by hand.

Fluid Saturation Process

After the model was packed with glass beads, a thin layer of silicone sealant was applied to the edges of the fibreglass model being careful not to cover the slit wells. A 3' x 3' x 1/8" thick sheet of Celtite Neoprene was then positioned on top of the tray and the top granite block was lowered and clamped onto the model. The entire apparatus was tilted and evacuated for saturation since a more efficient gravity stabilized front is created as a result of saturating from the down to updip end.

A total of six saturation ports, three on each opposing side of the model, were machined into the model to enhance saturation efficiency. The model fluids entered the apparatus from downdip and was pulled upward due to the vacuum at the updip end. Initially, de-aired, distilled water saturated the model. The pore volume, which was the volume of water taken into the system, and hence, the porosity was then determined. Next, the model was saturated with Faxam-100 oil in the same manner used for water saturation. The total volume water of displaced during oil saturation was equivalent the initial oil saturation. As a corollary, the volume of water remaining after no more water was produced was referred to as the irreducible water saturation. When the quick connect fittings were removed at the injection and production ends, a vacuum was maintained within the model as was confirmed by a vacuum regulator.

Preparation of A Bottom Water Model

Since this experimental study investigated marginal reservoirs containing a bottom water zone, a method was devised to create a bottom water zone and is listed in detail in Appendix C. Approximately two days were required to prepare a bottom water model.

A predetermined volume of 5% (by weight) sodium chloride solution, which corresponded to a percentage of the gross model thickness, was poured into the empty fibreglass tray. Glass beads were then sprinkled by hand with the aid of a beaker to cover the brine solution. Another thin layer of beads was added to compensate for the expansion due to the freezing of water. The model was then pushed, along with a 50 litre tub of clean, dry glass beads, into the walk-in cooler/freezer until the bottom water layer was completely frozen.

Once the bottom water layer was frozen, the remainder of the model was packed with the frozen glass beads using the Wygal particle distributor and any excess was trimmed off. The model was then saturated in the usual manner as quickly as possible to minimize the thawing effects of the bottom water layer. The refractive indices of the produced water solutions were measured in order to determine the quantity of bottom water lost due to melting using the lever rule and hence, the volume of bottom water remaining following saturation.

Creation of a Gas Zone

A gas zone was created by injecting a small quantity of inert nitrogen gas into the model prior to the experiment. It was hoped that gas injection would improve oil recovery by diverting the injected fluid away from the bottom water zone and into the oil zone and hence, mitigate the heat scavenging effects of bottom water. Nitrogen gas was injected at 1 psig for a period of one prototype year (12.18 minutes). A larger injection pressure was avoided since it would break the vacuum seal.

Conducting Experiments in the Model

Once the homogeneous model was packed and saturated, it was pushed into the walk-in cooler/freezer and cooled overnight to 3°C. For the bottom water model, it was necessary to allow the model to thaw out completely before it could be cooled. The injection vessels were filled with distilled water and de-aerated using a vacuum pump while the model was cooling in preparation for the experimental run.

Prior to each experiment, the chilling system in the fluid collection unit was turned on to cool the coils and the collection flasks were evacuated. The Labtech Notebook data acquisition software was then loaded into computer. The model was rolled out of the cooler/freezer and the thermocouple cables were connected to the thermocouples inside the fibreglass tray. Broken thermocouples or cable short circuits were detected when the cold junction cable value was displayed on the computer by Labtech. Furthermore, the pressure transducers could be checked and calibrated with the aid of Labtech. Labtech was then reloaded in preparation of the run, dry ice was added to the dry ice bath, the production line was connected to the desired outlet port, whether the vertical or horizontal producer, and the run experiment was ready to proceed.

It was crucial to record the time value at the beginning and conclusion of the injection of different fluids (water, steam or gas) from Labtech and thus, determine the lag time between fluid hook up and total injection length. In order to provide experimental consistency, 2000 cc samples were collected from the vacuum traps in graduated cylinders and labelled chronologically. Each run lasted for the duration of approximately two hours depending on the injection rate or two pore volumes of fluid were injected (2 P.V. cumulative volume injected). Fluid injection rates could be adjusted by controller on the Milroy pump.

Waterflood

Because steam was not required for a waterflood run, it was not necessary to pre-heat the boiler. De-aired, room temperature, distilled water was pumped through the injection line to flush out any trace fluids from previous experiments. The injection line was then inserted into the desired inlet port, that is, the vertical or horizontal injector. Water was then injected into the model and the produced samples were collected.

Steamflood in a Homogeneous Model

For a steam injection runs, it was crucial to pre-heat the oil bath in the boiler to the desired temperature. Feed water was pumped through the boiler to convert it to superheated steam and was mixed with room temperature water in proper proportions to form the required steam quality. This time, the injection line was flushed with steam before it was connected to the inlet.

Solvent-Steamflood

In solvent-steamfloods, the only variation was that the solvent Milroy pump was used to initially inject a specified volume of Heavy Virgin Naphtha into the model prior to steam injection. The steam Milroy pump was then attached, the injection line was flushed with steam and the steamflood commenced in the usual manner. The volume of solvent recovered was determined from the refractive index of the sample. However, because the solvent concentration changed as a result of evaporation over a short period of time, it was crucial to either measure the refractive index of the samples immediately after they were taken or if it was desired to record the information later, the cylinders were sealed with an air tight material.

Bottom Water Runs

Bottom water runs, like solvent-steamfloods, also required the services of the Refractometer in order to measure the volume of bottom water production using the refractive indices of the produced samples.

Gas Injection Runs

For gas injection runs, an inert gas cylinder was connected to the model using plastic tubing. In all the experiments, nitrogen was injected at a constant pressure of 1 psig which was monitored using a pressure regulator. Since the injection pressure was greater than atmospheric pressure, a slight drop in the vacuum occurred and could be seen by a decrease in the level of mercury in the manometer for the duration of gas injection.

Apparatus Cleanup

At the conclusion of the experiment, the aluminum clamps were removed and the cap block was removed. The Neoprene sheet was peeled off the model, shaken to remove any attached beads and then, disposed in a waste container. The glass beads were carefully removed to avoid damaging the thermocouples. Any broken thermocouples were replaced and the bent ones were repositioned. A degreasing agent followed by a laboratory detergent was applied by hand to the glass beads to remove all the residues of the hydrocarbons (Faxam-100 oil and Heavy Virgin Naphtha solvent) and water. The glass beads were placed into two 3 ft Stainless Steel cylinders set on risers and permitted to drain any water from the outlet line attached at the bottom the cylinder. The beads were dried by connecting the cylinders to air inlets and forcing air to flow through the beads.

Any excess silicone sealant was scraped off the tray using a metal chisel. A degreasing solution, followed by Varsol and acetone were applied to the tilted fibreglass model. After the waste was drained using a siphon, the traces of the cleaning agents were removed by using laboratory wipers. Plastic cylinders were washed with dishwashing

detergent while glass ones were cleaned using the laboratory detergent. Thus, the model was ready for the next experiment.

Data Analysis

Following each experiment, the data was recalled from Labtech Notebook and analyzed by a data spreadsheet program, such as Lotus 1-2-3 or Microsoft Excel. All pertinent data including porosity, initial fluid saturations, fluid recoveries, initial model temperature and cumulative pore volume injected were summarized in an experimental table. The following variables were then correlated as function of cumulative pore volume: % oil in sample, % cumulative oil recovery (%OOIP), % solvent in sample, % cumulative solvent recovery and average effluent temperature. Temperature top and cross-section profiles were constructed where applicable at 0.25, 0.50, 1.0 and 1.5 P.V. of steam injected.

Chapter 5

Discussion of the Results

Presentation of the Results

The following chapter is a discussion of the results of the present experimental study, using the low pressure, scaled model for investigating the steamflood process under bottom water conditions. The main emphasis of the study was on the use of a small amount of solvent with steam in an attempt to improve the steamflood efficiency. The purpose of using solvents in combination with steam was to increase steam injectivity in the oil zone, and create an initial flow path in the oil layer to divert the steam partially from the underlying water. The results of experiments using other strategies to better the steamflood efficiencies are included. Also provided in the section is a theoretical heat flow analysis performed on a selected steamflood experiment.

Various types of experiments were performed during the research investigation. Table 5.1 lists the pertinent values and results for all the experiments conducted during this investigation. The first group of runs consisted of base experiments which were compared with later experiments in order to observe the effects of different parameters such as solvent injection, solvent slug size, bottom water thickness, gas injection, injection-production interval locations and the use of alternative recovery schemes. These base experiments involved a continuous solvent flood in a homogeneous model, a solvent-steamflood in a homogeneous model and a steamflood with prior gas injection in a bottom model.

There were numerous, different runs carried out after the preliminary base experiments. A series of these proceeding experiments examined the effect of solvent slug size on oil recovery by a steamflood for cases of bottom water and no bottom water. Also studied was the effect of bottom water thickness on steamflood and solvent-steamflood responses. From these experiments one was able to determine if and why a solvent-steamflood was more effective than straight steam injection when bottom water was

Table 5.1. List of Completed Experiments

Run No.	Model Type	Type of Process	Porosity (%)	Soi (%)	Swi (%)	Bottom Water (% gross thickness)	Solvent Slug Size (PV)	Cum. Rec. (%OOIP)	Solvent Rec. (%)	Cum. PV Inj. (PV)
39	BW	SF	37.1	86.0	14.0	12.5	12.5	16.8	--	1.78
40	HM	CSI	33.7	92.5	7.5	--	--	26.8	89.5	2.25
41	HM	*	--	--	--	--	--	--	--	--
42	HM	*	--	--	--	--	--	--	--	--
43	HM	*	--	--	--	--	--	--	--	--
44	HM	Solvent-steamflood	33.7	92.9	7.1	--	--	27.1	70.4	2.33
45	HM	Solvent-steamflood	34.1	92.0	8.0	--	--	30.0	71.2	2.59
46	HM	Solvent-steamflood	38.7	80.9	19.1	--	--	27.7	33.1	2.07
47A	HM	W/F prior to SSF	33.6	93.0	7.0	--	--	19.1	--	1.54
47B	HM	SSF following W/F	33.6	75.3	24.7	--	--	33.5	44.9	2.03
48A	HM	W/F prior to SSF	33.4	92.7	7.3	--	--	19.8	--	1.69
48B	HM	SSF following W/F	33.4	74.3	25.7	--	--	33.5	58.9	2.25
49	BW	Solvent-steamflood	37.0	86.7	13.3	8.8	8.8	23.3	84.6	2.13
50	BW	Solvent-steamflood	35.8	91.2	8.8	10.2	10.2	25.4	88.5	2.26
51	BW	Solvent-steamflood	37.7	66.9	33.1	26.2	26.2	14.3	40.8	2.05
52	BW	*	--	--	--	--	--	--	--	--
53	BW	Solvent-steamflood	36.5	76.2	23.8	15.2	15.2	19.0	54.4	2.16
54	BW	Solvent-steamflood	36.1	91.0	9.0	12.2	12.2	22.6	89.8	2.39
55	HM	Gas inj. prior to SSF	34.3	90.3	9.1	--	--	26.8	87.7	2.37
56	HM	Gas inj. prior to SSF	33.6	93.0	6.3	--	--	27.0	90.9	2.43
57	BW	*	--	--	--	--	--	--	--	--
58	BW	Gas inj. prior to SSF	35.6	86.4	13.0	9.8	9.8	18.2	88.6	2.27
59	BW	Gas inj. prior to SSF	35.7	85.3	14.1	13.6	10.0	24.7	96.7	2.30
60	BW	Gas inj. prior to SF	35.9	76.3	23.4	17.6	--	13.6	--	2.31
61	BW	Gas inj. prior to SF	36.0	83.5	16.2	12.1	--	19.5	--	2.30

Table 5.1 (continued)

Run No.	Model Type	Type of Process	Porosity (%)	Soi (%)	Swi (%)	Bottom Water (% gross thickness)	Solvent Slug Size (PV)	Cum. Rec. (%OOIP)	Solvent Rec. (%)	Cum. PV Inj. (PV)
62	BW	Gas inj. prior to SSF	36.3	83.4	16.3	12.0	10.0	20.0	94.7	2.29
63	BW	SFPBW	36.3	77.5	22.5	15.4	--	17.0	--	2.26
64	BW	SFPBW	36.7	87.5	12.5	9.9	--	22.0	--	2.27
65	BW	SFPBW	36.1	73.4	26.6	19.6	20.0	19.8	73.0	2.29
66	HM	Solvent-steamflood	33.5	93.3	6.7	--	5.0	24.2	91.4	2.59
67	HM	Solvent-steamflood	33.5	92.5	7.5	--	15.0	25.9	97.0	2.43
68	HM	*	--	--	--	--	--	--	--	--
69	HM	*	--	--	--	--	--	--	--	--
70A	HM	W/F prior to SF	31.70%	87.9%	12.1%	--	--	27.69%	--	2.09
70B	HM	SF following W/F	31.7%	59.8%	40.2%	--	--	7.70%	--	2.10
74	HM	SF: vert.inj. & hor.prod.	32.0%	91.1%	8.9%	--	--	50.16%	--	2.21
75	HM	SF: hor.inj. & hor.prod.	33.8%	91.5%	8.5%	--	--	60.89%	--	2.12
76	HM	SF: hor.inj. & vert. prod.	33.9%	90.6%	9.4%	--	--	53.91%	--	2.16
77	HM	SF: vert. inj. & vert.prod.	32.4%	92.2%	7.8%	--	--	58.76%	--	2.14
78	BW	Solvent-steamflood	34.8%	79.7%	20.3%	7.59%	0.11	52.92%	99.20%	2.07
79	HM	Solvent-steamflood	32.5%	90.9%	9.1%	--	0.15	57.51%	99.93%	2.13
80	BW	Solvent-steamflood	33.3%	74.6%	25.4%	7.05%	0.20	46.21%	94.09%	2.19
81	BW	Repeat of Run 80	33.1%	91.1%	8.9%	8.12%	0.19	48.46%	99.95%	2.13
82	BW	Solvent-steamflood	33.0%	90.8%	9.2%	7.15%	0.28	54.31%	99.95%	2.14
83	BW	SF	33.4%	91.2%	8.8%	7.00%	--	56.60%	--	2.06
84	BW	Repeat of Run 80	32.4%	85.3%	14.7%	7.67%	0.19	52.05%	100.00%	2.12
86	HM	Repeat of Run 74	33.8%	90.9%	9.1%	--	--	51.87%	--	2.10
103	HM	*--SF (Repeat of Run 77)	32.2%	91.3%	8.7%	--	--	N/A	--	N/A
104	HM	SF (Repeat of Run 77)	32.8%	90.5%	9.5%	--	--	57.80%	--	2.13

(To test repeatability of run)

Table 5.1 (continued)

Key to Abbreviations:

HM: Homogeneous Model
 BW: Bottom Water Model
 SF: Continuous Steamflood (vert. inj. & vert. prod.)
 SSF: Solvent-Steamflood
 W/F: Waterflood
 CSI: Continuous Solvent Injection
 GISF: Gas Injection Prior to Steamflood
 GISSF: Gas Injection Prior to Solvent-Steamflood
 SFPBW: Steamflood with Partial Bottom Water Barrier

vert. inj.: Vertical Injector
 vert.prod.: Vertical Producer
 hor.inj.: Horizontal Injector
 hor.prod Horizontal Producer

Description of Misruns:

* — Misrun (unless otherwise specified, all misruns resulted an unsuccessful vacuum seal)
 Run 103 Experimental use of vacuum grease as a sealant unsuccessful.

present. The effect of gas injection prior to steamflooding on oil recovery from homogeneous and bottom water formations was studied in another set of runs. A similar group of experiments examined the change in oil recovery due to gas injection prior to the solvent-steamflood of reservoirs with or without a bottom water zone. Other experiments investigated the effect of injection-production interval locations. Another set of runs considered the implementation of a physical barrier between the oil and water zones during a steamflood to divert the steam away from the bottom water. In other experiments the model was waterflooded prior to solvent and steam injection. A map of the various experiments conducted is provided in Figure 5.1, where the abbreviations in the figure are the same as used in Table 5.1.

The corresponding tables and figures (recovery curves, bar plots and oil/steam ratio plots) for each experiment are included throughout the chapter as each experiment is discussed. The two sets of temperature profiles (top view and cross-sectional view) are referred to throughout the discussion and are grouped in Appendix A, in view of the massive volume of data processed.

The final stage of the research study involved a theoretical heat flow analysis of a steamflood. The analysis consisted of estimating the growth and volumes of the steam zone and hot water region during the steamflood using three classical steam injection theories developed by Lauwerier ⁶⁸, Marx and Langenheim ⁵ and Mandl and Volek ⁶⁹. A heat balance of the model was performed throughout the steamflood in order to estimate the amount of heat lost from the model during the experiment. The results of the analysis are provided in tabular form and are included throughout the discussion of the heat flow analysis. The four computer programs developed and implemented in this analysis are provided in Appendix B. These programs utilized the theories of Lauwerier, Marx and Langenheim and Mandl and Volek, as well as performing a heat balance in order to yield estimates of the generalized heat transfer behaviour that occurred in the model during an experiment.

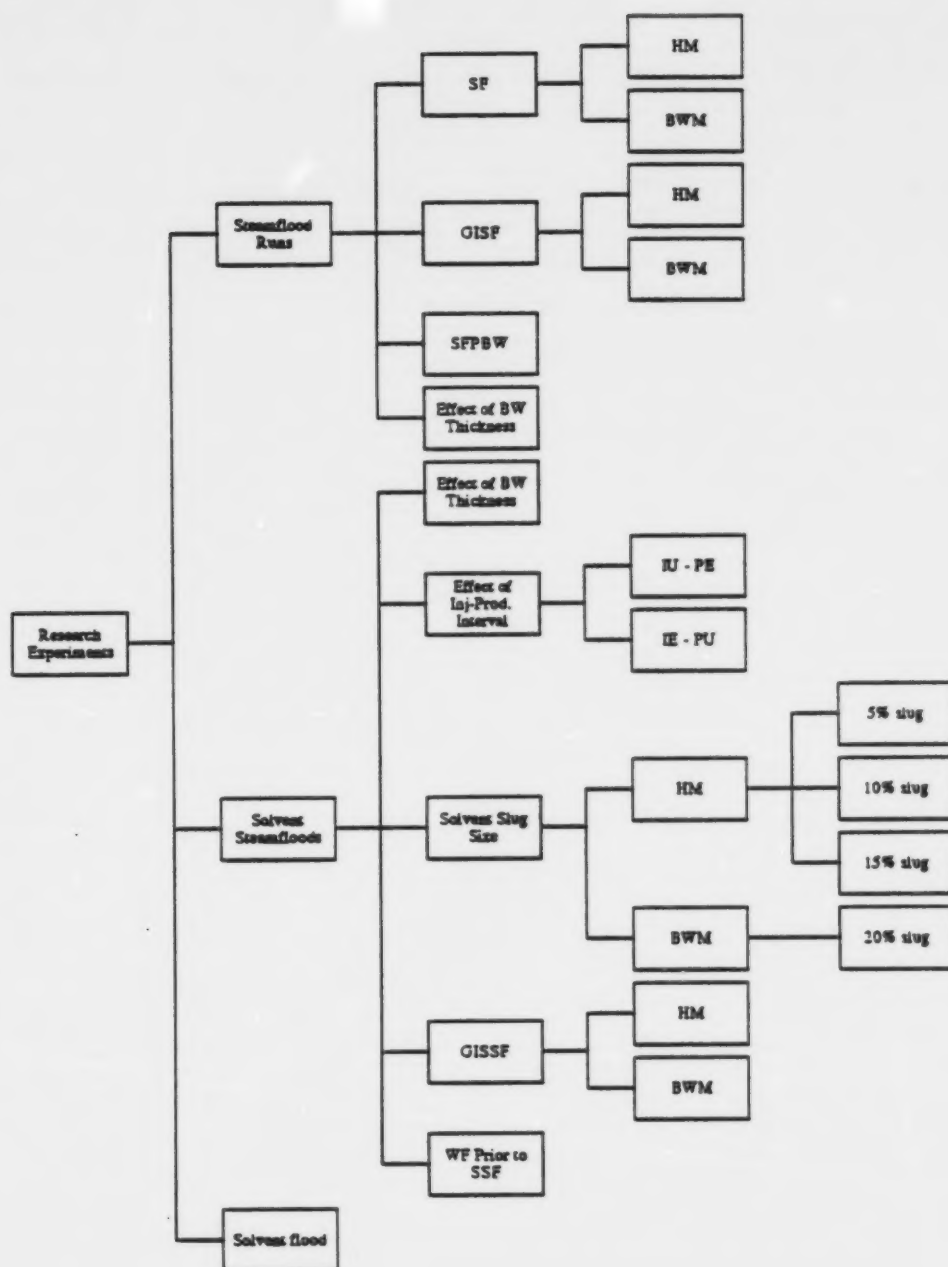


Figure 5.1 : Map of Experimental Runs Conducted During the Research Project

Steamflood versus Solvent-Steamflood Process

The steamflood process which is also known as a steam drive or steam displacement is a very important heavy oil recovery technique. Steamflooding is analogous to a waterflood in that steam is injected into the reservoir on a pattern basis, as in a waterflood. It has been reported ⁶² that a steamflood can be used quite effectively in light and moderately viscous oil reservoirs, also.

During a steamflood, steam is injected into the injection well resulting in the creation of a steam zone which expands radially outward from the injector into the reservoir as more steam is injected. The hot condensate leaving the steam zone creates a hot waterflood in front of the steam zone. As the hot condensate cools down to the formation temperature, it creates a cold waterflood effect ahead of the hot water and the steam zones. Therefore a steamflood process consists of a steam zone, a hot waterflood zone, and a cold waterflood zone. The oil recovery is due to the recovery mechanisms operating in each of the zones.

The steam zone which is at an approximately constant temperature T_s is the most essential component of a steamflood. Oil in this region is highly mobilized by the heating effect of the steam and is displaced by the gas drive effect of steam. Also the thermal expansion of oil further mobilizes the oil, and steam distillation of lighter fractions of the oil helps to lower the oil saturation as well.

The mobilized oil is displaced and banked up ahead of the steam zone in the condensate region. Before the steam invades the oil region ahead of the steam zone, the undisturbed oil zone has already been swept by the cold condensate and then the hot condensate. In essence, the advancing steam zone contacts the same oil saturation, whether the formation is previously waterflooded or not. An illustration of the different regions that exist in the reservoir during a steamflood is provided in Figure 5.2.

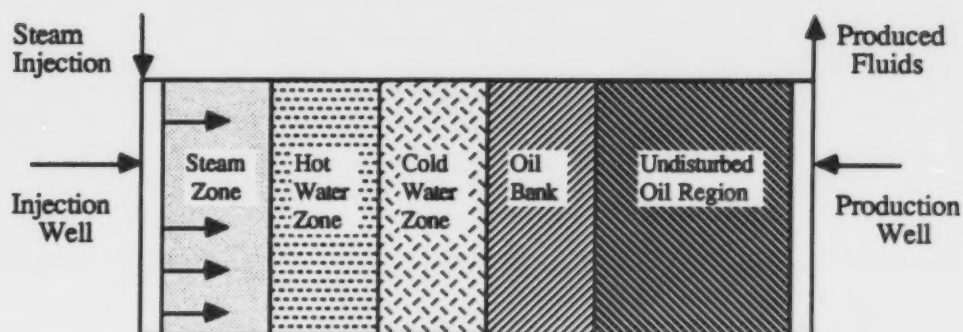


Figure 5.2: Schematic Diagram of a Steamflood Process

Excellent areal coverage is usually obtained during a steamflood due to the gravity segregation of the steam which causes the steam to rise up through the formation until it condenses. Gravity segregation of the steam is always present and can limit vertical sweep in thick reservoirs.

The efficiency of a steamflood process is strongly dependent on formation thickness, steam quality, steam temperature and the presence of bottom water, since these factors determine the rate of growth of the steam zone.

The presence of a bottom water layer in a thin heavy oil formation is undesirable since it provides a highly conductive flow path for the injected steam to underride the oil layer. This lowers the thermal efficiency of a steamflood because a majority of the steam's heat is scavenged by the underlying water.

The solvent-steamflood process is quite similar in nature to a steamflood except that a small slug of solvent is injected into the formation prior to steamflooding. The injected solvent channels directly into the oil region which forms an initial flow path for the steam. Therefore the heating effect of the steam can be more effectively utilized to mobilize and displace the oil in the reservoir. A schematic diagram of the solvent-steamflood process is given in Figure 5.3.

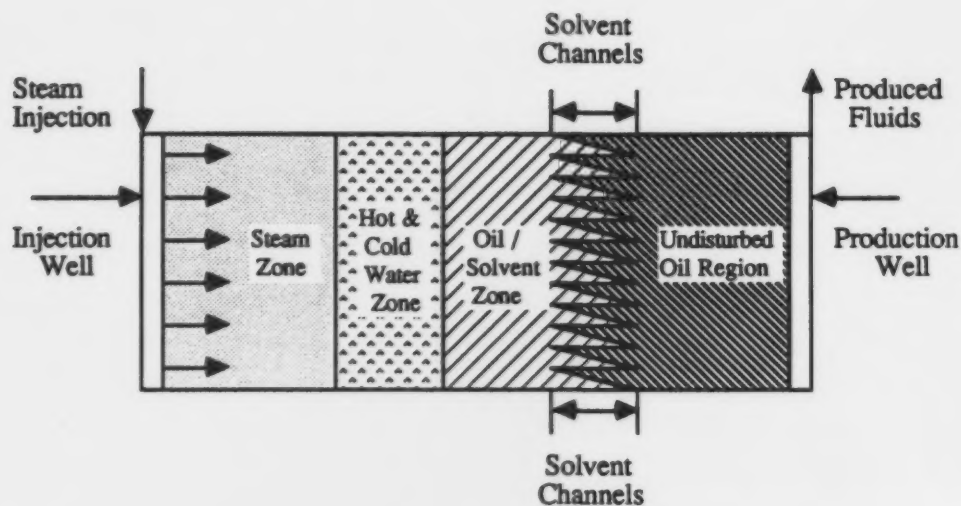


Figure 5.3 Schematic Diagram of Solvent - Steamflood Process

Thin heavy oil formations, with underlying water are considered to be uneconomic for a conventional steamflood for reasons discussed previously. Therefore the purpose of using solvents in combination with a steamflood is to improve steam injectivity in the oil zone, and create an initial flow path in the oil layer in order to divert the steam partially from the underlying water. It is believed that the solvent-steamflood process can be a economically viable heavy oil recovery method.

Typical Steamflood History in a Bottom Water Reservoir

To obtain a better understanding of the production history of a typical steamflood in a bottom water formation, consider Run 39, which consisted of a steamflood in a bottom water model. The purpose of the experiment was to provide one with reasonable insight into what results were to be expected in a continuous steamflood of a thin heavy oil formation, with underlying water. The model used in Run 39 had a bottom water layer thickness which was 12.5% of the gross model thickness, i.e. one-eighth of the model thickness. The experimental results of Run 39 are listed in Table 5.2.

The net oil recovery of Run 39 was 16.8% which was substantially less than the recovery yielded by Run 26 which was a conventional steamflood of a homogeneous model. The oil recovery in Run 26 was 31.8%, as reported by Proctor, George and Farouq Ali ⁶³, which indicates that the bottom water layer in Run 39 had an adverse effect on the effectiveness of the steamflood process.

The recovery curve created for Run 39, given in Figure 5.4, appeared to be a fairly linear relationship with no drastic increase or drop in the oil recovery at any time during the experiment. This suggested that the steam preferentially flowed underneath the oil layer into the less flow resistant bottom water region due to lower steam injectivity of the above oil layer. Therefore a majority of the steam heat was scavenged by the underlying water zone. Due to the bottom water layer, the formation of a well-pronounced steam zone and oil bank in the model was inhibited which resulted in an unstable steam displacement of the oil and thus a poor oil recovery.

Two bar plots of volume as a percentage of oleic phase in each sample taken versus cumulative volume injected and instantaneous produced water-oil ratio (WOR) versus cumulative volume injected were generated from the results of Run 39 and are provided in Figures 5.5 and 5.6, respectively. As well as indicating little oil production, both plots gave no indication that a well-defined steam breakthrough occurred during the experiment. It was therefore concluded that a very unstable steam displacement existed in the model due to a poorly developed steam zone. The absence of a pronounced steam breakthrough and the lack of an established steam zone both pertained to the presence of bottom water in the model.

Figure 5.7 provides a graph of instantaneous oil/steam ratio versus cumulative oil produced for Run 39. The plot does not have a very drastic rise in the oil/steam ratio values during the first part of the experiment which again suggested that the steam displacement of the oil was not as efficient during the steamflood process due to the bottom water zone.

Table 5.2 : Run 39 Conventional Steamflood of Bottom Water Model

HC Pore Volume :	13400.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15580.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	37.1%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	86.0%	Total Flow Rate of Steam :	229.20 cc/min
Initial H ₂ O Satn. :	14.0%	Steam Vol. Inj. :	27775.0 cc (1.78 PV)
		Bottom Water Layer Thickness :	12.5% (% Gross Thickness)

Final Oil Saturation : 71.6 %

Net Oil Recovery : 16.8 %

Cyl. No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj.		Oil Prod. (cc)	Cum. Oil Rec. (cc)	Oil-Steam Inst Prod. Ratio		WOR	Inst. Oil Prod. % of Sample
		(cc)	(P.V.)		(cc) [(%OOIP)]				
1	1895	1895	0.12	125	125	0.9%	0.0706	14.16	6.6%
2	2130	4025	0.26	250	375	2.8%	0.1330	7.52	11.7%
3	1910	5935	0.38	290	665	5.0%	0.1790	5.59	15.2%
4	2050	7985	0.51	205	870	6.5%	0.1111	9.00	10.0%
5	1990	9975	0.64	240	1110	8.3%	0.1371	7.29	12.1%
6	2005	11980	0.77	170	1280	9.6%	0.0926	10.79	8.5%
7	1930	13910	0.89	205	1485	11.1%	0.1188	8.41	10.6%
8	1965	15875	1.02	140	1625	12.1%	0.0767	13.04	7.1%
9	1910	17785	1.14	130	1755	13.1%	0.0730	13.69	6.8%
10	2020	19805	1.27	35	1790	13.4%	0.0176	56.71	1.7%
11	1920	21725	1.39	110	1900	14.2%	0.0608	16.45	5.7%
12	2020	23745	1.52	115	2015	15.0%	0.0604	16.57	5.7%
13	2030	25775	1.65	115	2130	15.9%	0.0601	16.65	5.7%
14	2000	27775	1.78	120	2250	16.8%	0.0638	15.67	6.0%

Figure 5.4 :Run 39 Continuous Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

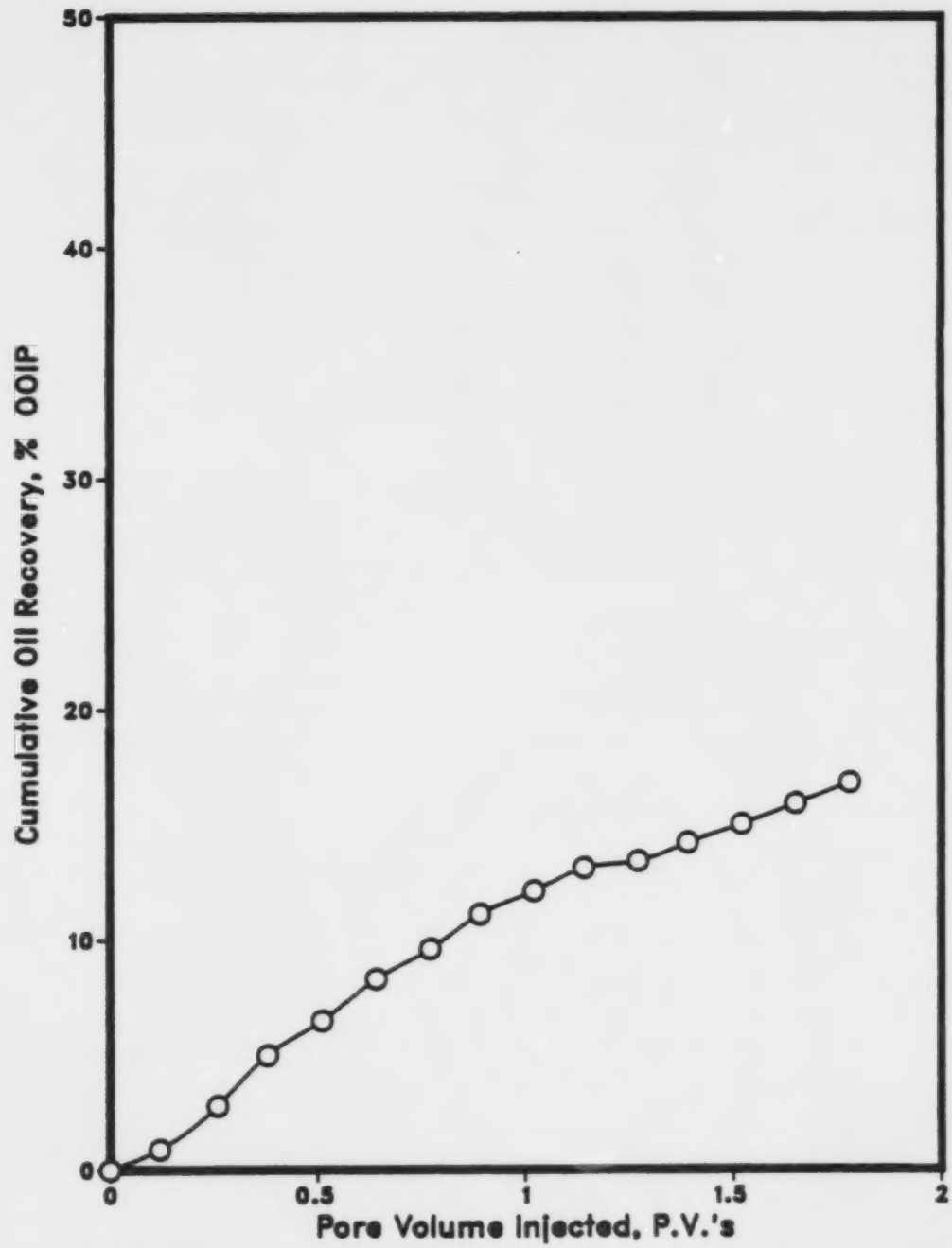


**Figure 5.5 :Run 39 Continuous Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

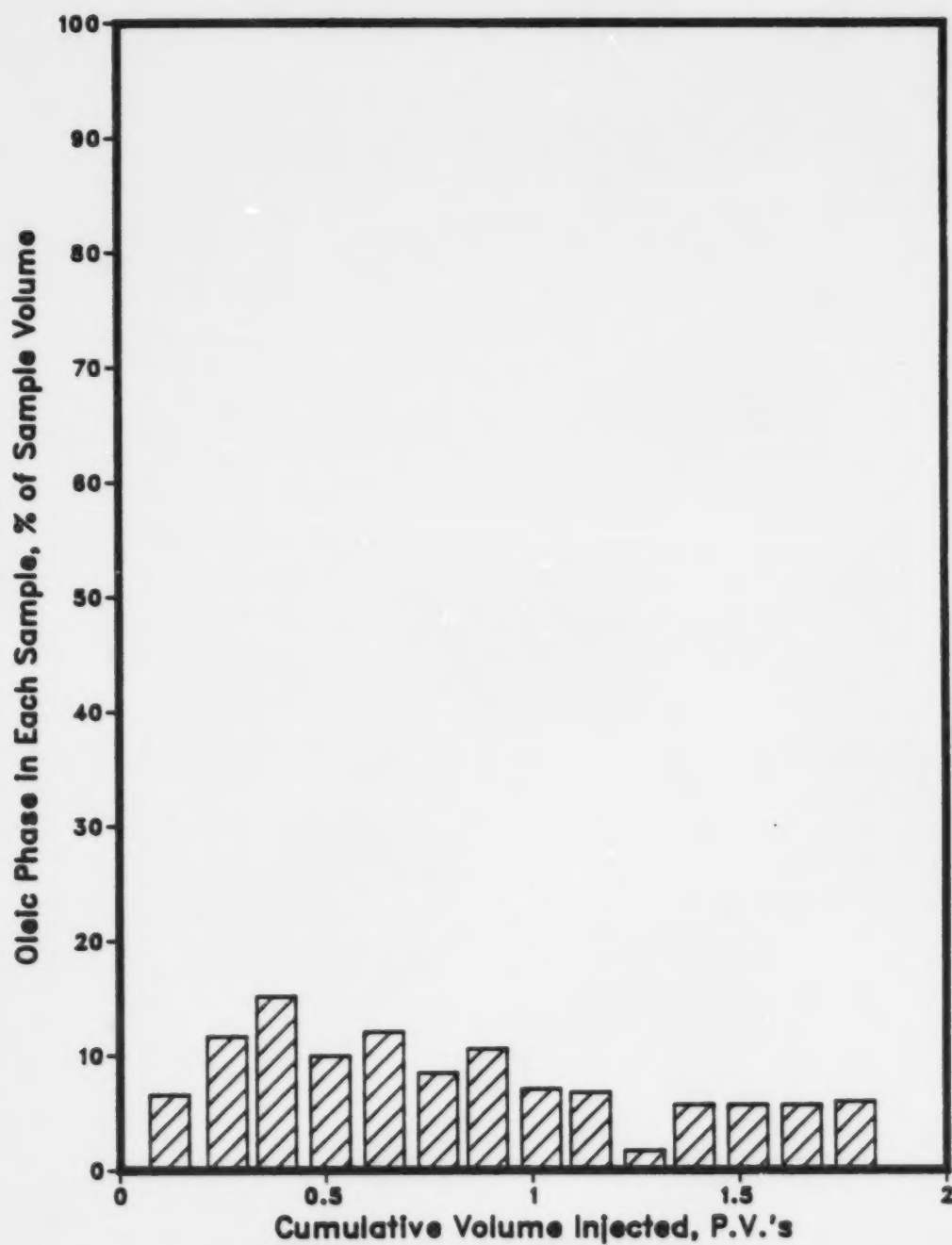


**Figure 5.6 :Run 39 Continuous Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

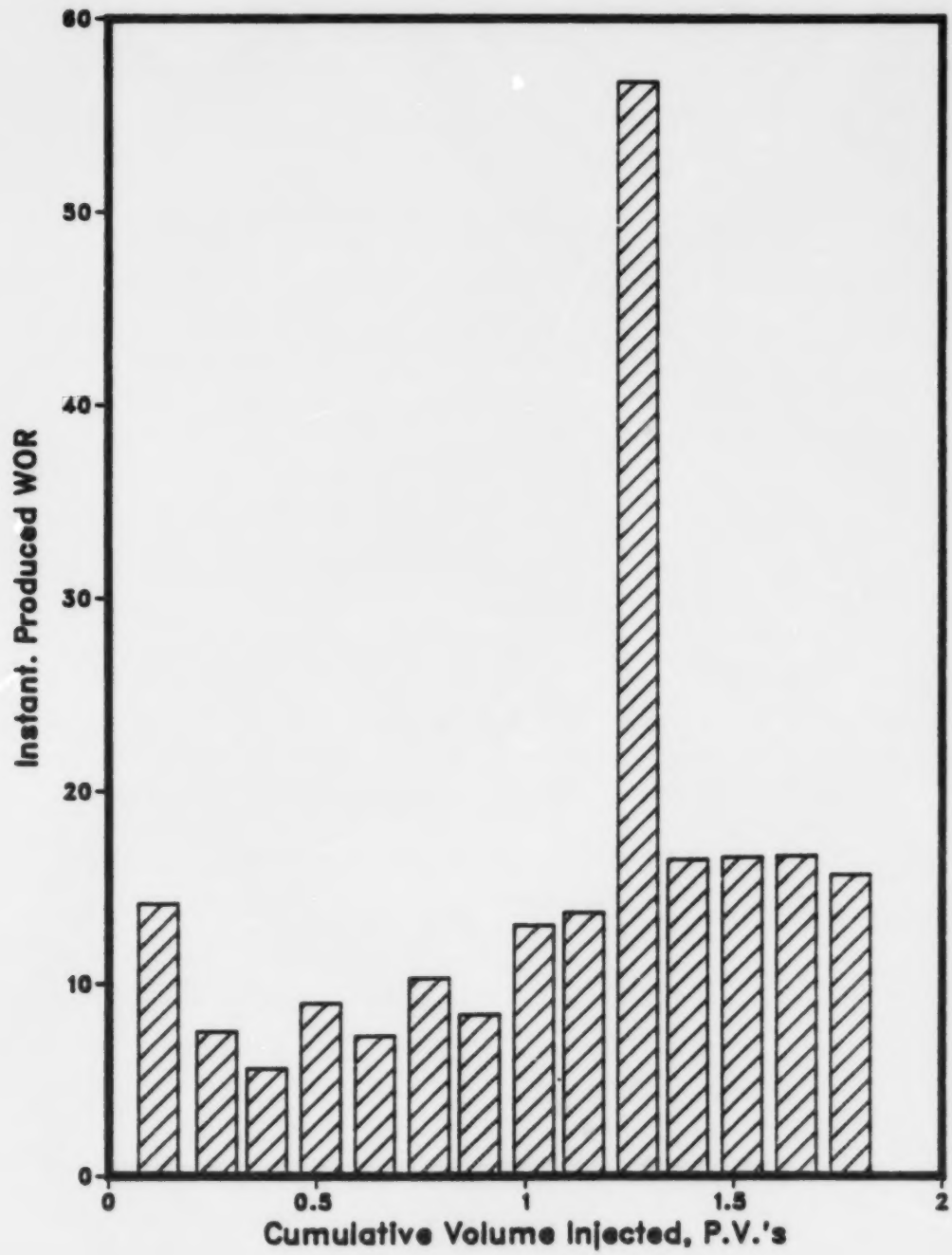
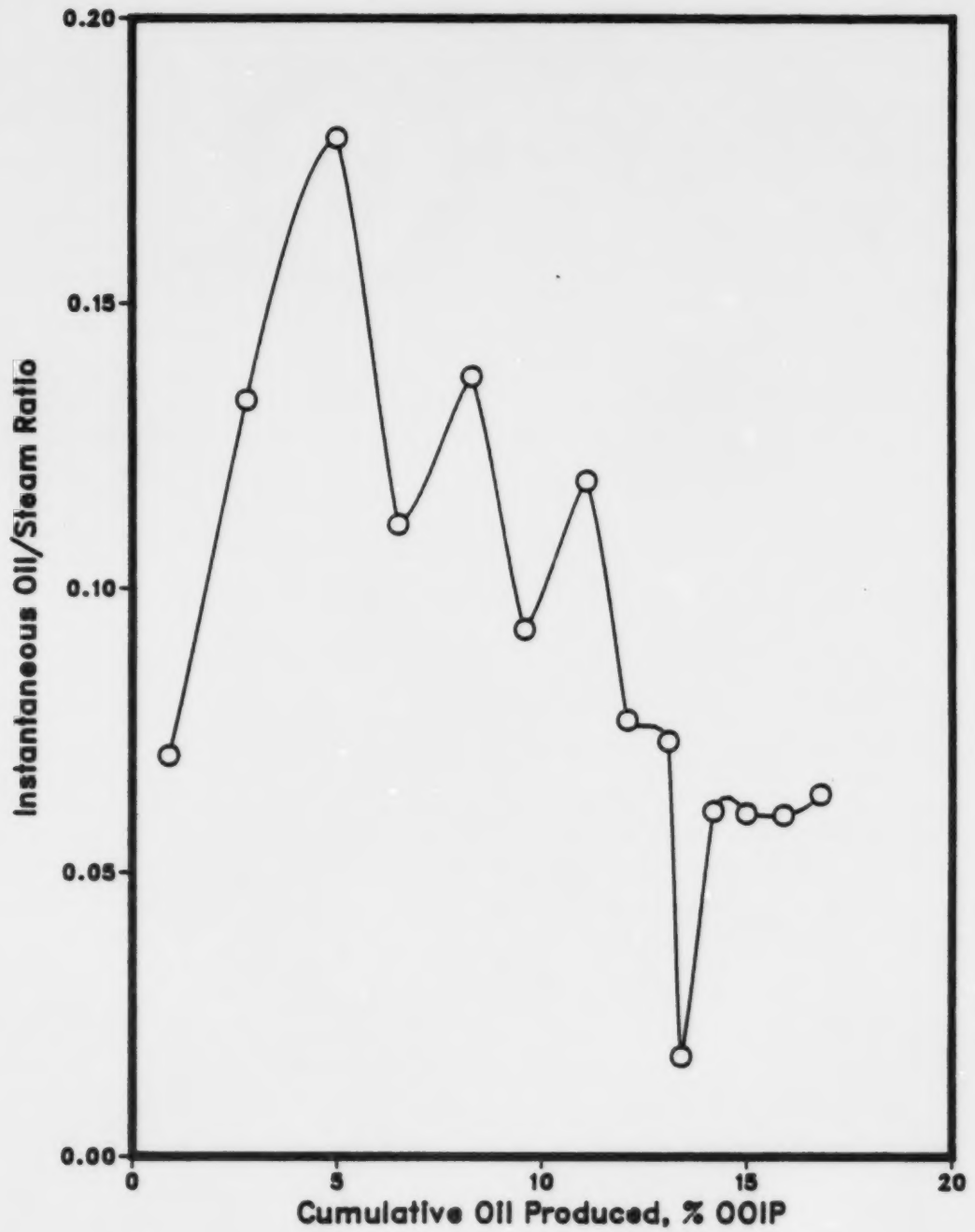


Figure 5.7 :Run 39 Continuous Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced



The top view temperature profiles given in Figures A.1 through A.6 and the cross-sectional temperature profiles provided in Figures A.7 through A.10 for Run 39 illustrate that the injected heat of the steam advanced faster through the lower half of the model than the upper section. The heat travelled faster through the lower section of the model since the steam had a higher injectivity in the underlying water zone than in the highly viscous oil layer. Therefore less of the injected steam was utilized to mobilize and displace the oil in the upper portion of the model due to the heat scavenging properties of the bottom water zone. Only at advanced times heating of the upper oil layer was significant enough to give additional oil recovery, and arrest the drop in oil/steam ratio.

All of the plots and temperature profiles for Run 39 indicated that the presence of bottom water during a steamflood process had a very unfavourable effect on the total amount of oil recovered from the model. The lower steam injectivity of the viscous oil zone forced the steam to flow into the underlying water which hindered the growth of the steam zone in the model. The lack of a steam zone allowed for a poor steam displacement of the inplace oil and therefore less oil was mobilized and displaced by the injected steam. The consequence of this inefficient displacement was a reduced oil recovery. The results of Run 39 enabled one to achieve a better idea of what to expect during a continuous steamflood of a bottom water formation.

Base Experiments for Comparison Purposes

A wide range of base experiments were carried out during the research. The data collected from these base runs were used to determine the injection properties of the solvent in the oil-saturated model. The results of the base experiments were also compared with later experiments to decide what effect such parameters as solvent slug injection, solvent slug size, bottom water thickness, gas injection, injection-production interval location and a physical barrier had on the oil recovery and thermal efficiency of a steamflood process implemented in a thin heavy oil formation, with underlying water.

The first base run was a continuous solvent flood in the homogeneous (i.e. no bottom water) model. The intention of the solvent flood was to enable one to estimate the injection behaviour of the solvent in the homogeneous model during the experiment. Another series of base experiments involved implementing a solvent-steamflood process in a homogeneous model. The results of these runs were then be compared to later solvent-steamflood experiments carried out in a bottom water model. The process of gas injection prior to a steamflood of a bottom water model was conducted in order to represent a base run which could be compared to the results of solvent-steamflood runs carried out in a bottom water model to determine how effective the use of a solvent slug prior to steamflooding would be.

Continuous Solvent Flood

Run 40 involved flooding a oil-saturated, homogeneous model with the chosen solvent (Heavy Virgin Naphtha). Table 5.3 lists pertinent data recorded from Run 40 such as the oil and solvent recoveries obtained during the experiment. Production began shortly after solvent injection was initiated and the majority of this production was solvent, suggesting that solvent breakthrough occurred almost immediately. This indicated that solvent channelling occurred almost immediately and thus the solventflood was an unstable

Table 5.3 : Run 40 Solventflood Performed With Homogeneous Model

Porosity = 33.7 %

Bulk Volume = 42005 cc

Pore Volume = 14140 cc

Initial HC Pore Volume = 13075 cc

Initial Oil Saturation = 92.47 %

Initial Water Saturation = 7.53 %

Total Solvent Injected = 2.25 P.V. (31700 cc)

Solvent Injection Rate = 200 cc/min.

Net Oil Recovery : 26.8 % Solvent Recovery : 89.5 %

Cylinder No.	Solvent Conc. (%)	Total Volume Prod. (cc)	Cum. HC Vol. Prod		Oil Prod. (cc)	Cum. Oil Prod. (cc)		Cum. Oil Rec. (%)	Cum. Solvent Rec.		Inst. HC Prod. % of Sample
			(cc)	(P.V.)		Prod. (cc)	(cc)		(cc)	(%)	
1	59	1700	1700	0.12	697.00	697.00	5.33	5.33	1003.0	3.16	41.0%
2	79	1515	3215	0.23	318.15	1015.15	7.76	7.76	2199.9	6.94	21.0%
3	80	1510	4725	0.33	302.00	1317.15	10.07	10.07	3407.9	10.75	20.0%
4	84	1120	5845	0.41	179.20	1496.35	11.44	11.44	4348.7	13.72	16.0%
5	85	1730	7575	0.54	259.50	1755.85	13.43	13.43	5819.2	18.36	15.0%
6	88	1480	9055	0.64	177.60	1933.45	14.79	14.79	7121.6	22.47	12.0%
7	87	1705	10760	0.76	221.65	2155.10	16.48	16.48	8605.0	27.15	13.0%
8	89	1345	12105	0.86	147.95	2303.05	17.61	17.61	9802.1	30.92	11.0%
9	90	1570	13675	0.97	157.00	2460.05	18.81	18.81	11215.1	35.38	10.0%
10	91	1455	15130	1.07	130.95	2591.00	19.82	19.82	12539.2	39.56	9.0%
11	91	1675	16805	1.19	150.75	2741.75	20.97	20.97	14063.5	44.36	9.0%
12	94	1595	18400	1.30	95.70	2837.45	21.70	21.70	15562.8	49.09	6.0%
13	94	1895	20295	1.44	113.70	2951.15	22.57	22.57	17344.1	54.71	6.0%
14	94	1550	21845	1.54	93.00	3044.15	23.28	23.28	18801.1	59.31	6.0%
15	95	1740	23585	1.67	87.00	3131.15	23.95	23.95	20454.1	64.52	5.0%
16	95	1680	25265	1.79	84.00	3215.15	24.59	24.59	22050.1	69.56	5.0%
17	96	1750	27015	1.91	70.00	3285.15	25.13	25.13	23730.1	74.86	4.0%
18	96	1690	28705	2.03	67.60	3352.75	25.64	25.64	25352.5	79.98	4.0%
19	95	1790	30495	2.16	89.50	3442.25	26.33	26.33	27053.0	85.34	5.0%
20	96	1380	31875	2.25	55.20	3497.45	26.75	26.75	28377.8	89.52	4.0%

displacement. The cumulative oil recovery curve (Figure 5.8) is smooth and gradually increases, also suggesting that an oil bank did not form in the model during the experiment.

All samples taken during Run 40 were mostly solvent with the remainder of the sample being oil as is evident in Figure 5.9. The gradual drop in oil content of each sample and lack of pressure fluctuations at the production well during the solventflood again suggested that a poorly defined oil bank formed due to immediate solvent channelling which is characteristic of an unstable displacement.

Figures A.11 through A.18 display the top view temperature profiles of the model at upper and lower levels for every 0.25 pore volumes for the first two pore volumes of solvent injected during the experiment. The injected solvent was at room temperature (21°C) which was different than the initial model temperature of 30°C. The solvent was not at the same temperature as the model so that the temperature profiles could provide a better indication of where the solvent was going in the model during the run. These temperature contours indicate that the solvent advanced faster through the lower portion than the upper region of the model. The first few profiles also suggest that solvent channelling was quite prevalent in the model. The cross-sectional temperature profiles for the first pore volume of solvent injected are given in Figures A.19 through A.22 and also illustrate that the solvent tended to channel in the lower half of the model throughout the experiment.

During the initial stages of the run, channelling started soon after solvent injection. As the run progressed the solvent was dispersed transversely outwards from the swept zone causing an increased oil mobility in parts of the unswept region. The newly mobilized oil of the unswept area entered the main solvent flow path resulting in the growth of the swept zone. A gradual rise in the cumulative oil recovery then occurred due to the subsequent production of this newly mobilized oil. The rise in cumulative oil recovery could also be partially attributed to the flowing solvent further reducing the oil saturation in the swept zone. The overall low oil recovery was due to solvent channelling creating a

Figure 5.8 :Run 40 Solventflood of Aberfeldy Model
Cumulative Oil Recovery Vs. Cumulative Volume Injected

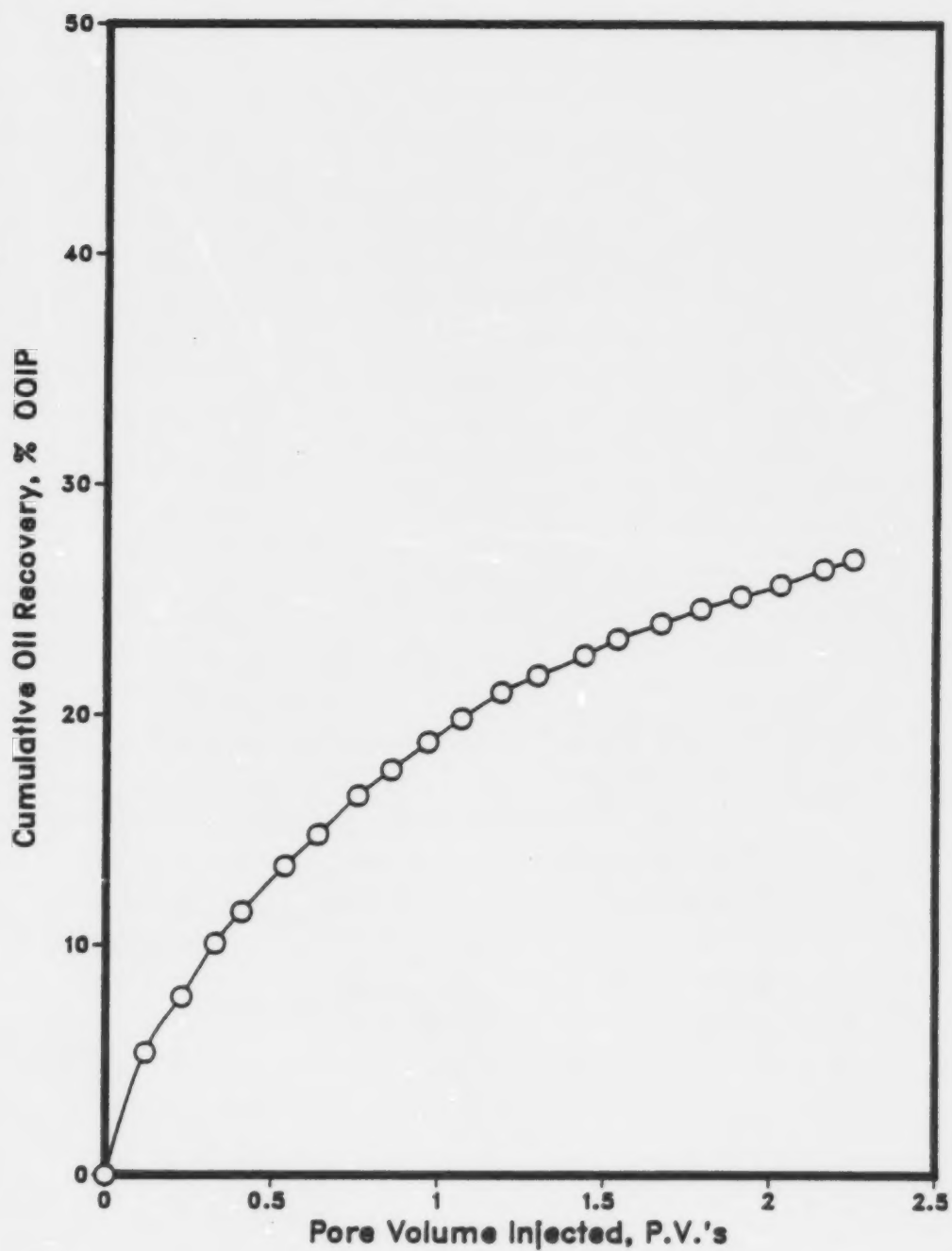
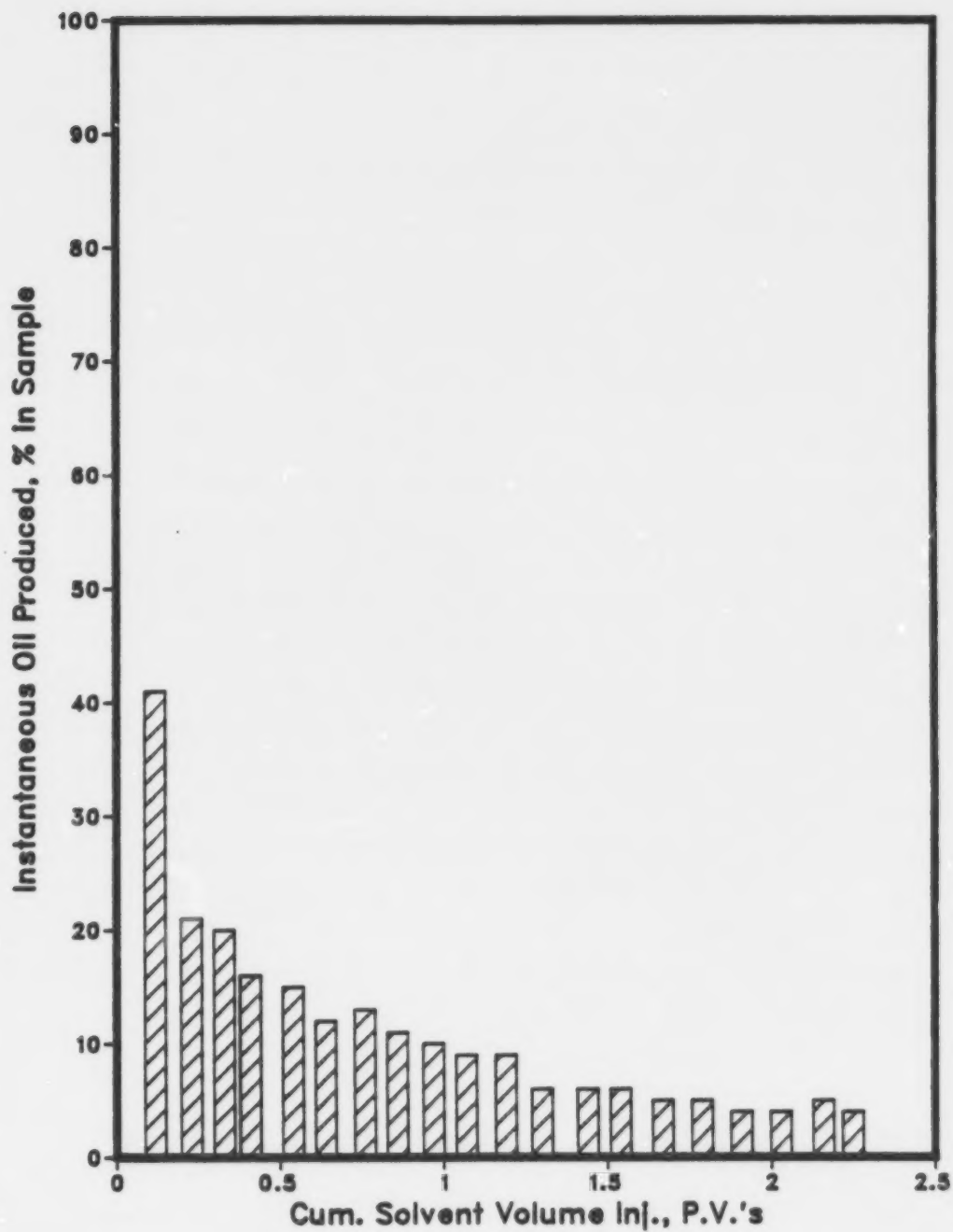


Figure 5.9 :Run 40 Solventflood of Aberfeldy Model
Instantaneous Oil Produced Vs. Cumulative Volume Injected



small swept zone that prevented an oil bank from developing and a stable displacement from being realized.

The oil recovery for Run 40 was relatively poor at 26.75 % which is comparable to previous waterfloods such as Run 7 (26.47 %) and Run 22 (25.91 %). Cumulative solvent recovery was at 89.52 %. The high solvent recovery was due to the immediate and continuous solvent channelling towards the production well during the run which resulted in less solvent being left in the model as a residual hydrocarbon saturation.

From the experimental results of Run 40 it appeared that the solvent channelled through the oil immediately upon injection and continued to do so throughout the experiment. This type of injection behaviour of the solvent was desirable in the context of a steamflood, because the solvent channels formed would aid in increasing the injectivity of steam into the oil during a steam injection process. The higher steam injectivity could allow a steam injection process to be more thermally efficient since less of the steam's heat would be lost to such heat sinks as overburden, underburden, adjacent formations and bottom water zones. Therefore the injected steam could be utilized more effectively in mobilizing and displacing the in-place oil.

Solvent-Steamflood

Runs 44, 45 and 46 involved injecting a small solvent slug into an oil-saturated, homogeneous model prior to a continuous steamflood. Tables 5.4, 5.5 and 5.6 present the pertinent data and results for Runs 44, 45 and 46, respectively. These runs were designed to evaluate the reproducibility of the experimental results and gain experience with this type of experiment.

The purpose of the solvent slug prior to steam injection was to create solvent channels into the oil region through which the injected steam could more easily penetrate and thus, more efficiently mobilize the oil. Since more oil could be mobilized and displaced, a larger oil bank (actually solvent and oil) would form and a more stable steam displacement would result. The greater stability of the steam injection process resulted in a prolonged time until steam breakthrough and an improved overall oil recovery.

The solvent slug size used in these experiments was 10 % of the pore volume. This value was chosen because Alikhan⁶⁴ stated that beyond a particular slug size, which he found to be about 10% of the pore volume depending upon the viscosity contrast between the oil and the solvent, the solvent slug would not be efficiently produced and the net result would be a decrease in total oil and solvent recovery.

Comparing the oil recovery curves for Runs 44, 45 and 46 (Figures 5.10, 5.14 and 5.18, respectively) to that of Run 40 (Figure 5.8) it is evident that the shapes of the solvent-steamflood curves are not as smooth as Figure 5.8 where only the solvent was injected continuously. In the very early stages of the solvent-steamfloods the oil recovery rose quite sharply. The steep increase in the recovery curves (Figures 5.10, 5.14 and 5.18) represented the oil and solvent, positioned ahead of the steam zone, forming a bank in the vicinity of the production well which was subsequently produced during the initial stages of the run. The curve then gradually started to level off due to the breakthrough of the steam and water at the production well. The steam breakthrough resulted in a less stable, less efficient displacement and led to a drop in oil production as illustrated in

Figures 5.11, 5.12, 5.15, 5.16, 5.19 and 5.20. After the solvent-steamflood recovery curves began to level off these curves once again started to increase and were shaped similar to the latter part of the solvent flood recovery curve. The gradual rise in oil production was caused by additional oil being mobilized in the unswept and swept zones. Oil recovered from the unswept region was mobilized (viscosity reduction) by the heating characteristics of the steam. The oil produced from the swept zone was also recovered due to the heating properties of the steam which lowered the viscosity of the remaining oil and further reduced the oil saturation in the swept region. The final stages of the solvent-steamflood curves were not as smooth as the solvent flood curve due to small humps existing near the end of the solvent-steamflood curves. These small humps were probably linked to small pockets of oil in the swept region that were finally mobilized and produced.

The bar plots of volume as a percentage of oleic phase in each sample collected versus the cumulative volume injected for Runs 44 (Figure 5.11), 45 (Figure 5.15) and 46 (Figure 5.19) were similar to one another. The peaks represent increased oil content in production and the lows reflect a decrease in the oil content of the production. The highs and lows of these plots correspond quite closely to slope variations in the recovery curves. An increase in the recovery curve slope indicates a rise in oil production and a decrease reflected a drop in oil production. Figures 5.12 (Run 44), 5.16 (Run 45) and 5.20 (Run 46) are bar graphs representing instantaneous water/oil ratio versus cumulative volume injected. For Figures 5.12, 5.16 and 5.20 the peaks are increases in the water/oil ratio of the instantaneous production and the valleys indicate drops in the instantaneous water/oil ratio. The highs and lows for Figures 5.12, 5.16 and 5.20 also correspond reasonably well with the slope variations of the recovery curves.

Figures 5.13, 5.17 and 5.21 are plots of instantaneous oil/steam ratio versus cumulative oil produced. A distinct peak in the oil/steam ratio occurred for all three runs between 10 and 20% production of the original oil in place. After the peak the curve drops and then gradually levels off. The peak represents the oil produced due to the steam

Table 5.4: Run 44 Solvent-Steamflood With Homogeneous Model

HC Pore Volume:	13140.0 cc	Type of Oil Used:	Faxam-100
Pore Volume:	14140.0 cc	Initial Model Temperature:	3.00 C
Bulk Volume:	42005.0 cc	Water Feed Flow Rate:	213.60 cc/min
Porosity:	33.7%	Boiler Feed Flow Rate:	29.20 cc/min
Initial Oil Satn.:	92.9%	Total Flow Rate of Steam:	242.80 cc/min
Initial H2O Satn.:	7.1%	Solvent Flow Rate:	200.00 cc/min
Solvent Vol. Inj.:	1400.0 cc (10.0% PV)	Steam Vol. Injected:	31575 cc (2.23 PV)

Net Oil Recovery : 27.1% Solvent Recovery : 70.4% Final Oil Saturation : 67.8%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	(%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst. Prod. WOR	HC Prod. % of Sample
1	52%	965	965	965	463	463	3.5%	502	35.9%	0.0000	0.00	100.0%
2	52%	1620	2585	785	377	840	6.4%	910	65.0%	0.0000	1.06	48.5%
3	8%	1990	4575	270	248	1088	8.3%	932	66.6%	0.1570	6.37	13.6%
4	6%	2100	6675	435	409	1497	11.4%	958	68.4%	0.2613	3.83	20.7%
5	4%	2090	8765	510	490	1987	15.1%	978	69.9%	0.3228	3.10	24.4%
6	2%	2115	10880	370	363	2350	17.9%	985	70.4%	0.2120	4.72	17.5%
7	0%	1985	12865	230	230	2580	19.6%	985	70.4%	0.1311	7.63	11.6%
8	0%	2020	14885	163	160	2740	20.9%	985	70.4%	0.0860	11.63	7.9%
9	0%	1985	16870	130	130	2870	21.8%	985	70.4%	0.0701	14.27	6.5%
10	0%	2040	18910	100	100	2970	22.6%	985	70.4%	0.0515	19.40	4.9%
11	0%	2015	20925	105	105	3075	23.4%	985	70.4%	0.0550	18.19	5.2%
12	0%	2000	22925	85	85	3160	24.0%	985	70.4%	0.0444	22.53	4.3%
13	0%	1955	24880	85	85	3245	24.7%	985	70.4%	0.0455	22.00	4.3%
14	0%	2015	26895	75	75	3320	25.3%	985	70.4%	0.0387	25.87	3.7%
15	0%	2010	28905	85	85	3405	25.9%	985	70.4%	0.0442	22.65	4.2%
16	0%	2075	30980	70	70	3475	26.4%	985	70.4%	0.0349	28.64	3.4%
17	0%	1995	32975	80	80	3555	27.1%	985	70.4%	0.0418	23.94	4.0%

Figure 5.10 :Run 44 Solvent-Steamflood
Cumulative Oil Recovery Vs. Cumulative Volume Injected

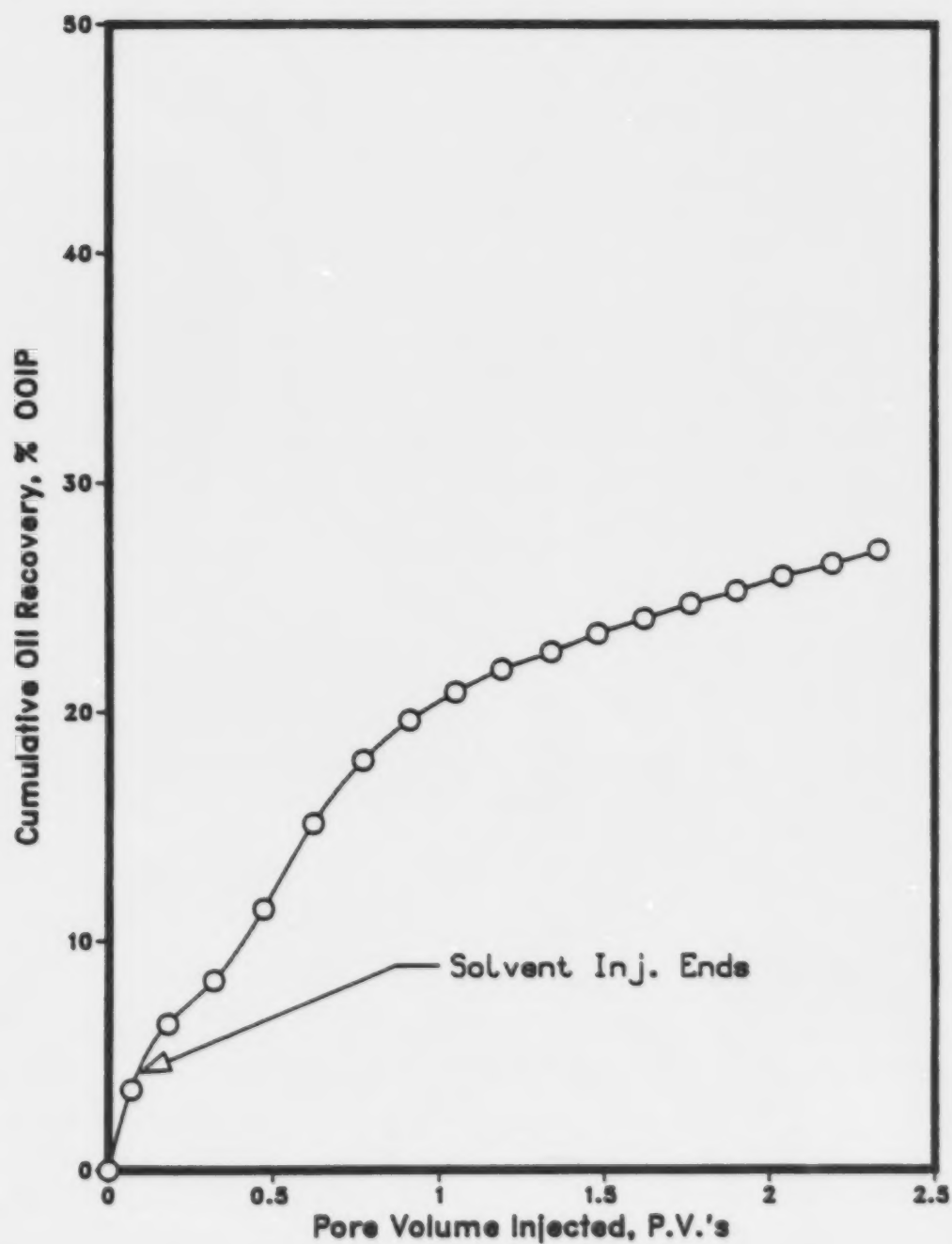


Figure 5.11 :Run 44 Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected

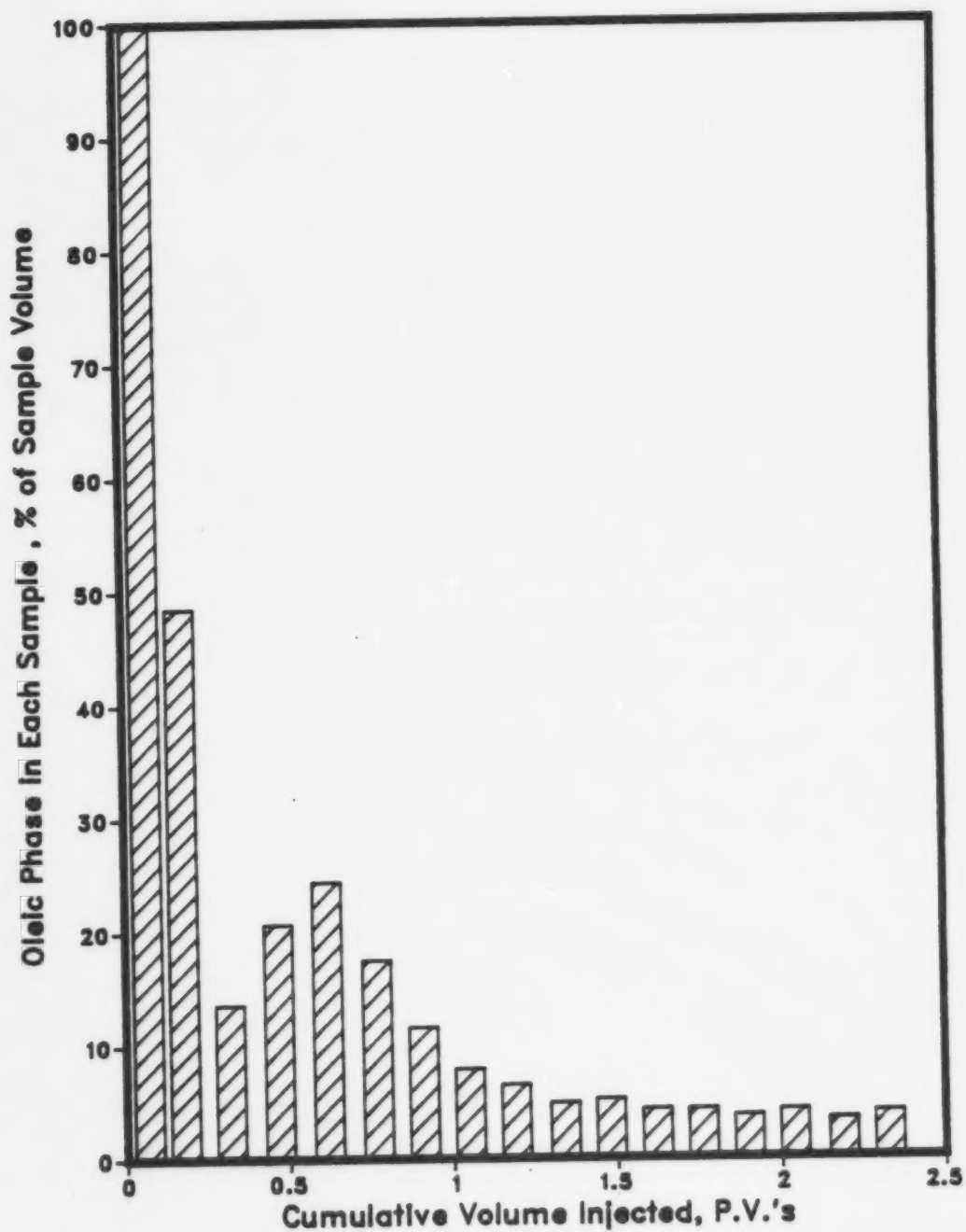


**Figure 5.12 :Run 44 Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

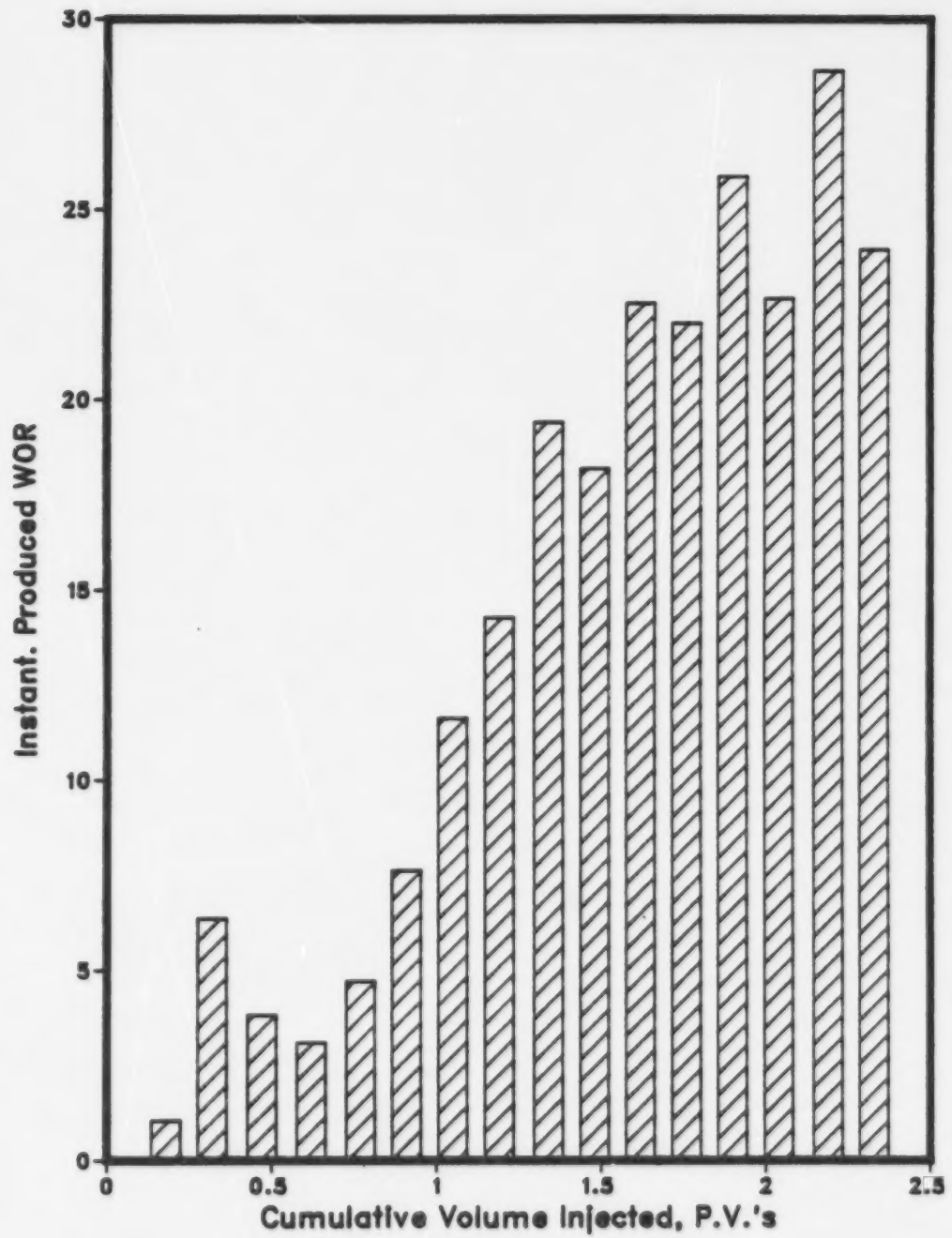


Figure 5.13 :Run 44 Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced

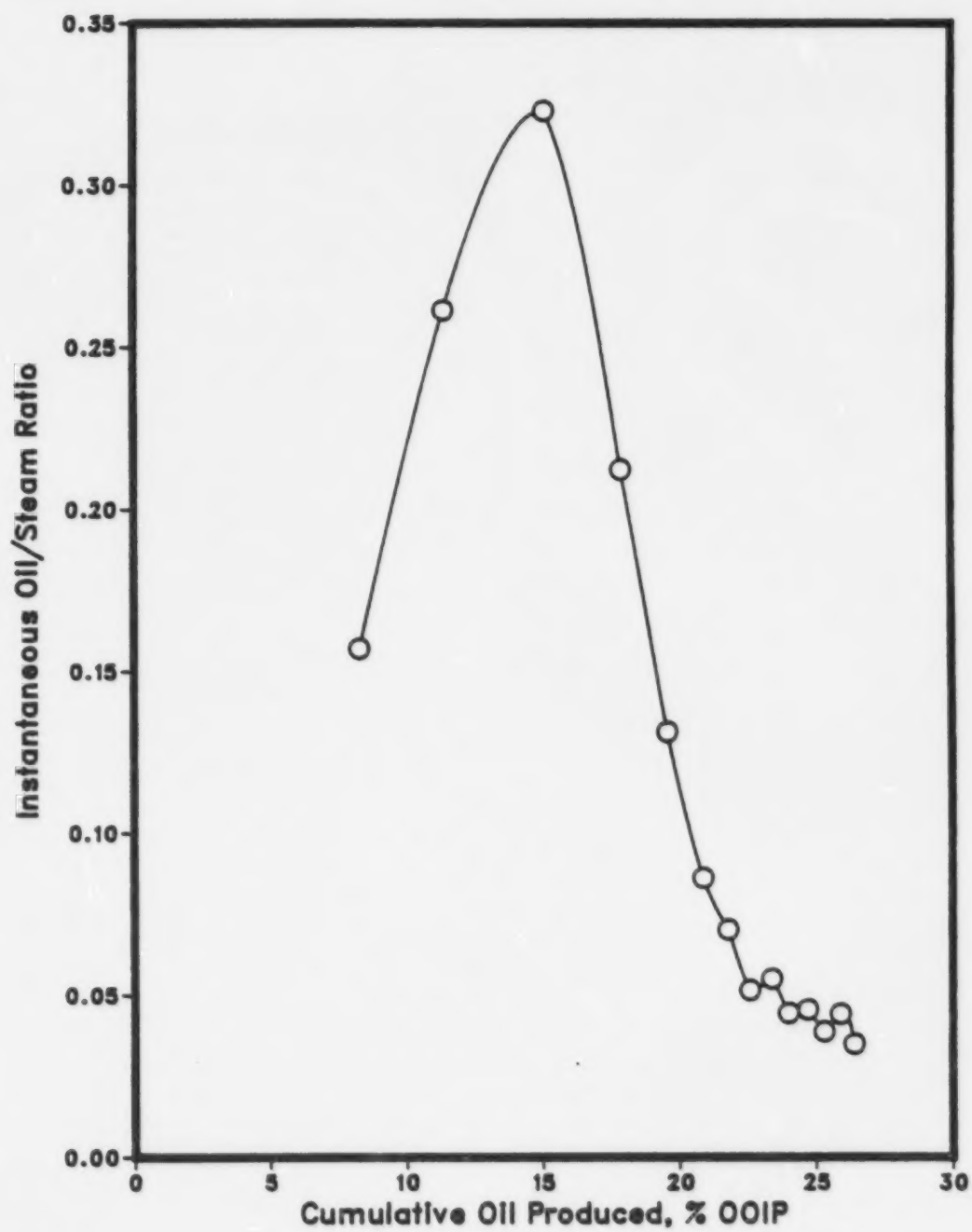


Table 5, 5 : Run 45 Solvent-Steamflood With Homogeneous Model

HC Pore Volume : 13180.0 cc	Type of Oil Used : Faxam-100
Pore Volume : 14320.0 cc	Initial Model Temperature : 3.00 C
Bulk Volume : 42005.0 cc	Water Feed Flow Rate : 213.60 cc/min
Porosity : 34.1%	Boiler Feed Flow Rate : 29.20 cc/min
Initial Oil Satn. : 92.0%	Total Flow Rate of Steam : 242.80 cc/min
Initial H ₂ O Satn. : 8.0%	Solvent Flow Rate : 200.00 cc/min
Solvent Vol. Inj. : 1400.0 cc (10.0% PV)	Steam Vol. Injected : 35655 cc (2.49 PV)

Net Oil Recovery : 30.0% Solvent Recovery : 71.2% Final Oil Saturation : 64.5%

Cyl. No.	Solvent Conc. (%)	Total Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	HC Prod (cc)	Oil Prod (cc)	Cum. Oil Rec. (cc)	Cum. Oil Rec. (%OOIP)	Oil-Sol. Rec. Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	47%	575	575	575	305	305	2.3%	0.0000	0.00	100.0%
2	62%	640	1215	620	236	541	4.1%	0.0000	0.03	96.9%
3	59%	395	1610	345	141	682	5.2%	0.0000	0.14	87.3%
4	24%	1965	3575	320	243	925	7.0%	0.1945	5.14	16.3%
5	8%	2030	5605	375	345	1270	9.6%	0.2266	4.41	18.5%
6	4%	1800	7405	465	446	1716	13.0%	0.3483	2.87	25.8%
7	3%	2000	9405	330	320	2036	15.4%	0.1976	5.06	16.5%
8	1%	1960	11365	290	287	2323	17.6%	0.1737	5.76	14.8%
9	0%	2020	13385	245	245	2568	19.5%	0.1380	7.24	12.1%
10	0%	1950	15335	185	185	2753	20.9%	0.1048	9.54	9.5%
11	0%	1965	17300	145	145	2898	22.0%	0.0797	12.55	7.4%
12	0%	1920	19220	130	130	3028	23.0%	0.0726	13.77	6.8%
13	0%	2025	21245	100	100	3128	23.7%	0.0519	19.25	4.9%
14	0%	1970	23215	105	105	3233	24.5%	0.0563	17.76	5.3%
15	0%	1990	25205	90	90	3323	25.2%	0.0474	21.11	4.5%
16	0%	2000	27205	85	85	3408	25.9%	0.0444	22.53	4.3%
17	0%	2030	29235	75	75	3483	26.4%	0.0384	26.07	3.7%
18	0%	1900	31135	175	175	3658	27.8%	0.1014	9.86	9.2%
19	0%	1980	33115	105	105	3763	28.6%	0.0560	17.86	5.3%
20	0%	1940	35055	105	105	3868	29.3%	0.0572	17.48	5.4%
21	0%	2000	37055	80	80	3948	30.0%	0.0417	24.00	4.0%

Figure 5.14 :Run 45 Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

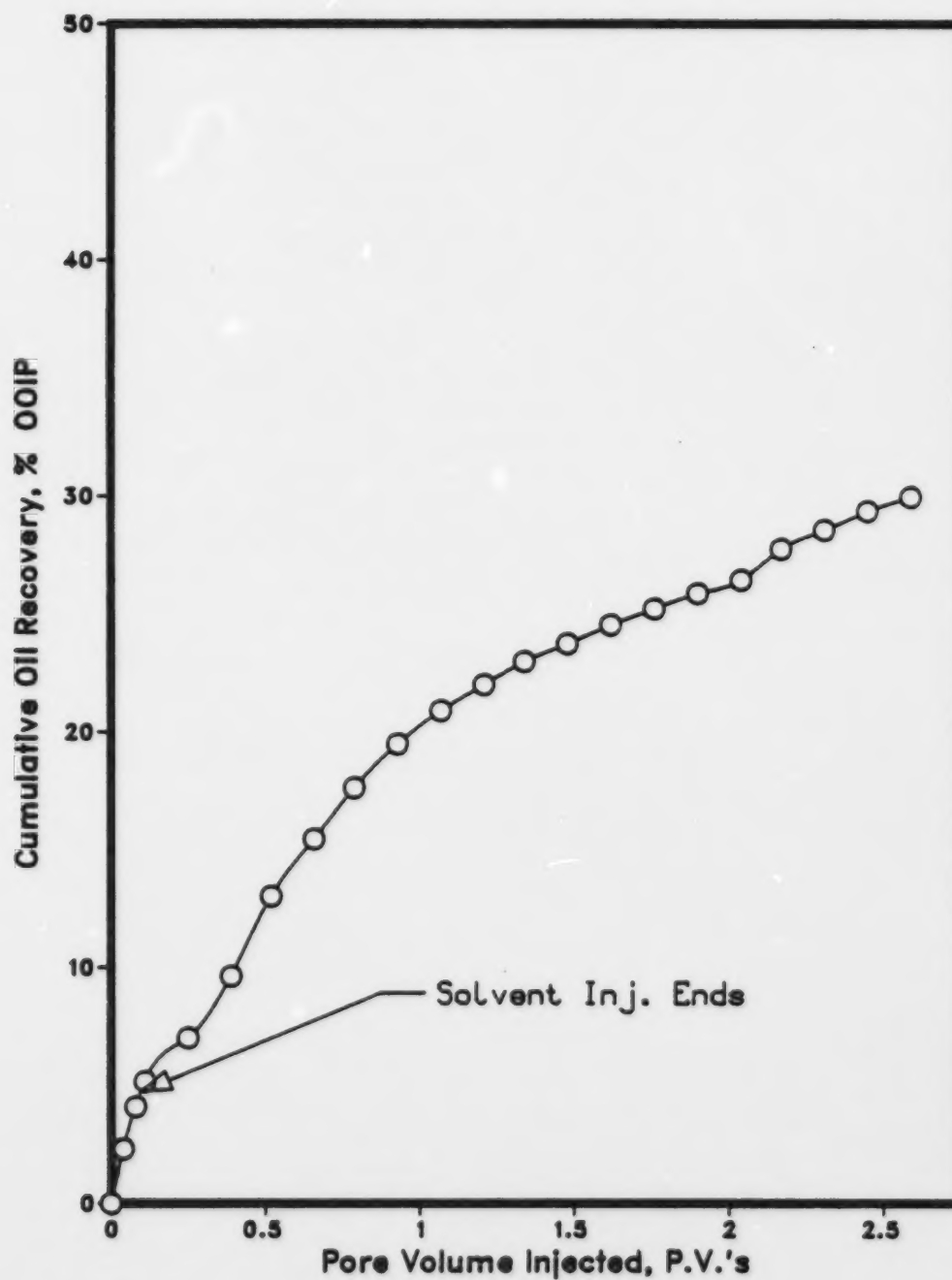


Figure 5.15 :Run 45 Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected

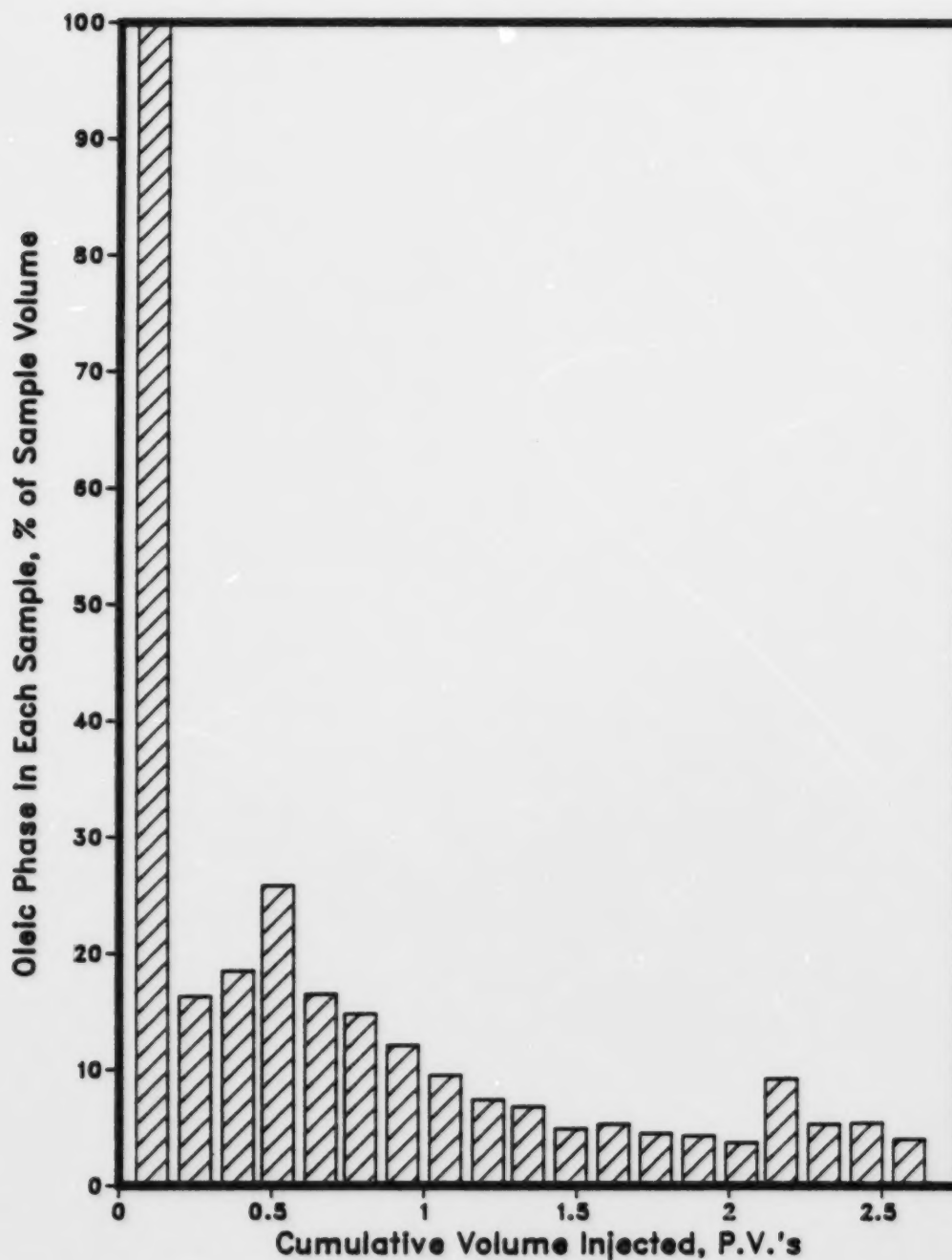


Figure 5.16 :Run 45 Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected

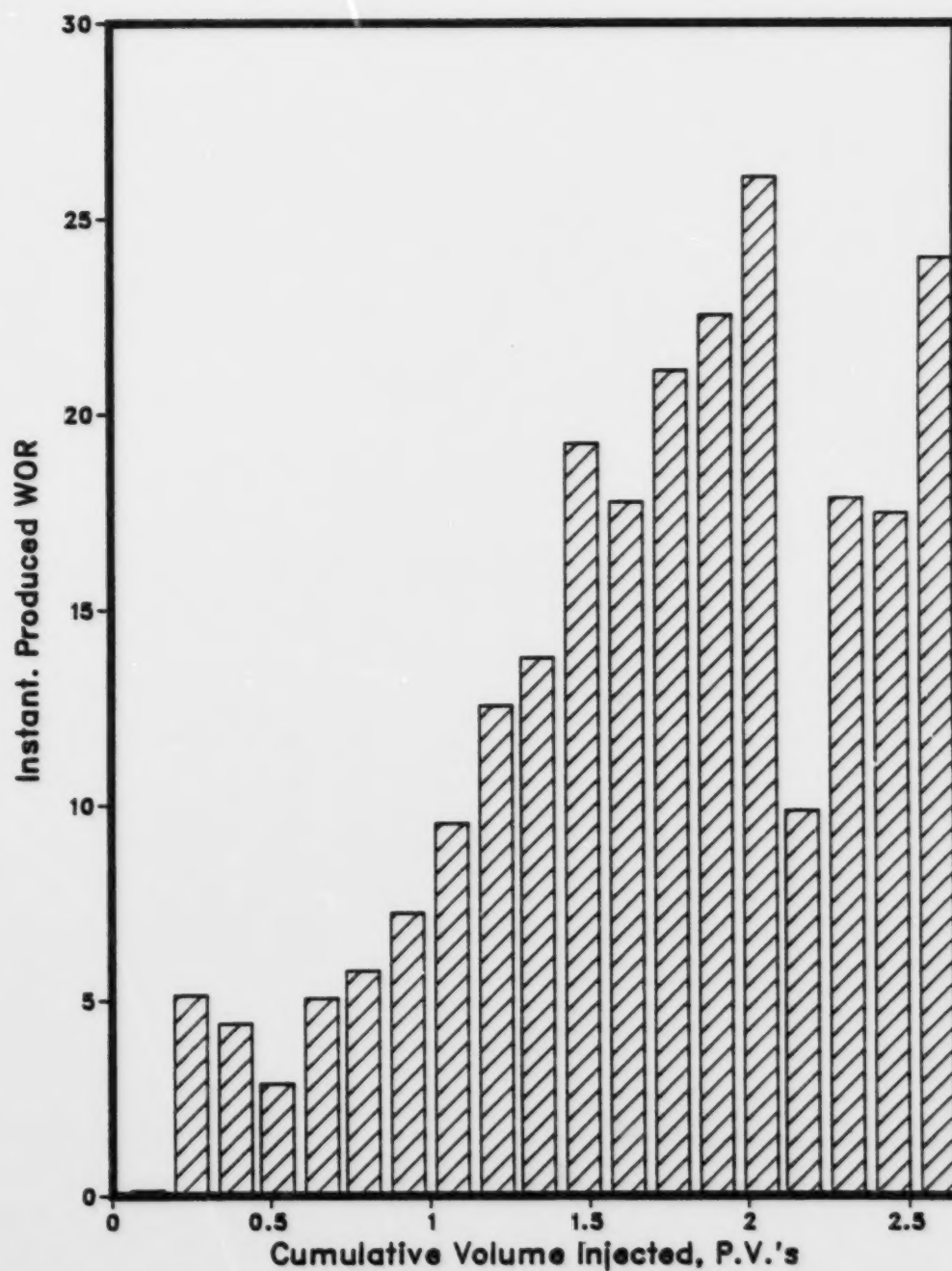


Figure 5.17 :Run 45 Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced

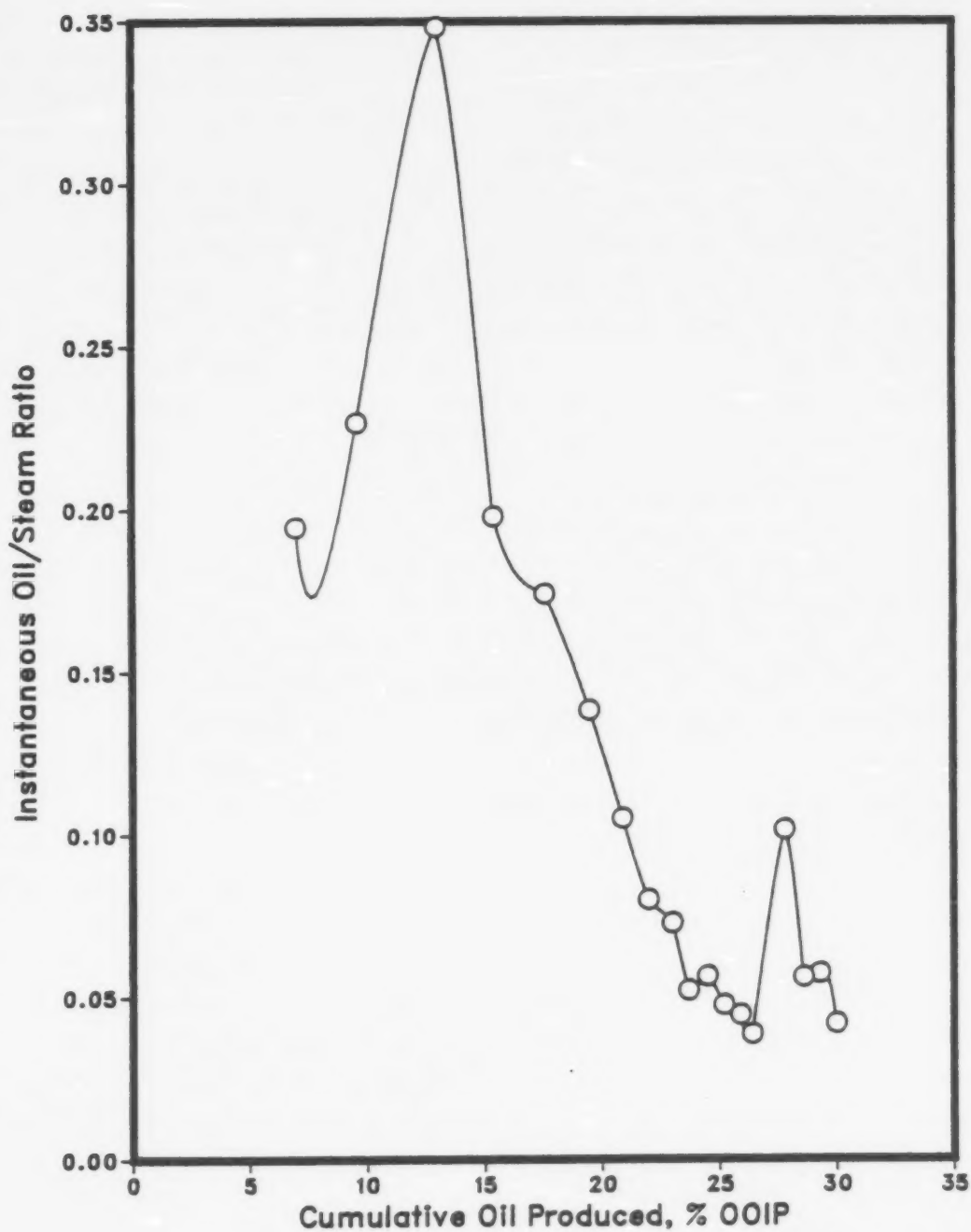


Table 5.6 : Run 46 Solvent-Steamflood With Homogeneous Model

HC Pore Volume :	13140.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	16250.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	213.60 cc/min
Porosity :	38.7%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	80.9%	Total Flow Rate of Steam :	242.80 cc/min
Initial H ₂ O Satn. :	19.1%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	1500.0 cc (10.0% PV)	Steam Vol. Injected :	32170 cc (1.98 PV)

Net Oil Recovery : 27.7% Solvent Recovery : 33.1% Final Oil Saturation : 58.5%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)	(cc)	(%)	Cum. Sol. Rec. (cc)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	26%	350	350	0.02	350	259	2.0%	259	6.1%	91	0.0000	0.00	100.0%
2	39%	380	730	0.04	380	232	3.7%	491	15.9%	239	0.0000	0.00	100.0%
3	42%	680	1410	0.09	370	215	5.4%	706	26.3%	394	0.0000	0.84	54.4%
4	16%	385	1795	0.11	95	80	6.0%	786	27.3%	409	0.3276	3.05	24.7%
5	15%	1820	3615	0.22	260	221	7.7%	1007	29.9%	448	0.1667	6.00	14.3%
6	5%	1920	5535	0.34	245	233	9.4%	1240	30.7%	460	0.1463	6.84	12.8%
7	4%	2075	7610	0.47	410	394	12.4%	1634	31.7%	476	0.2462	4.06	19.8%
8	3%	2000	9610	0.59	375	364	15.2%	1998	32.5%	487	0.2308	4.33	18.8%
9	2%	1880	11490	0.71	330	323	17.7%	2321	32.9%	494	0.2129	4.70	17.6%
10	1%	1950	13440	0.83	250	248	19.6%	2569	33.1%	496	0.1471	6.80	12.8%
11	0%	2100	15540	0.96	220	220	21.2%	2789	33.1%	496	0.1170	8.55	10.5%
12	0%	2080	17620	1.08	165	165	22.5%	2954	33.1%	496	0.0862	11.61	7.9%
13	0%	1990	19610	1.21	150	150	23.6%	3104	33.1%	496	0.0815	12.27	7.5%
14	0%	2035	21645	1.33	95	95	24.3%	3199	33.1%	496	0.0490	20.42	4.7%
15	0%	1950	23595	1.45	90	90	25.0%	3289	33.1%	496	0.0484	20.67	4.6%
16	0%	2045	25640	1.58	70	70	25.6%	3359	33.1%	496	0.0354	28.21	3.4%
17	0%	1975	27615	1.70	85	85	26.2%	3444	33.1%	496	0.0450	22.24	4.3%
18	0%	2020	29635	1.82	80	80	26.8%	3524	33.1%	496	0.0412	24.25	4.0%
19	0%	1900	31535	1.94	70	70	27.4%	3594	33.1%	496	0.0383	26.14	3.7%
20	0%	2135	33670	2.07	45	45	27.7%	3639	33.1%	496	0.0215	46.44	2.1%

Figure 5.18 :Run 46 Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

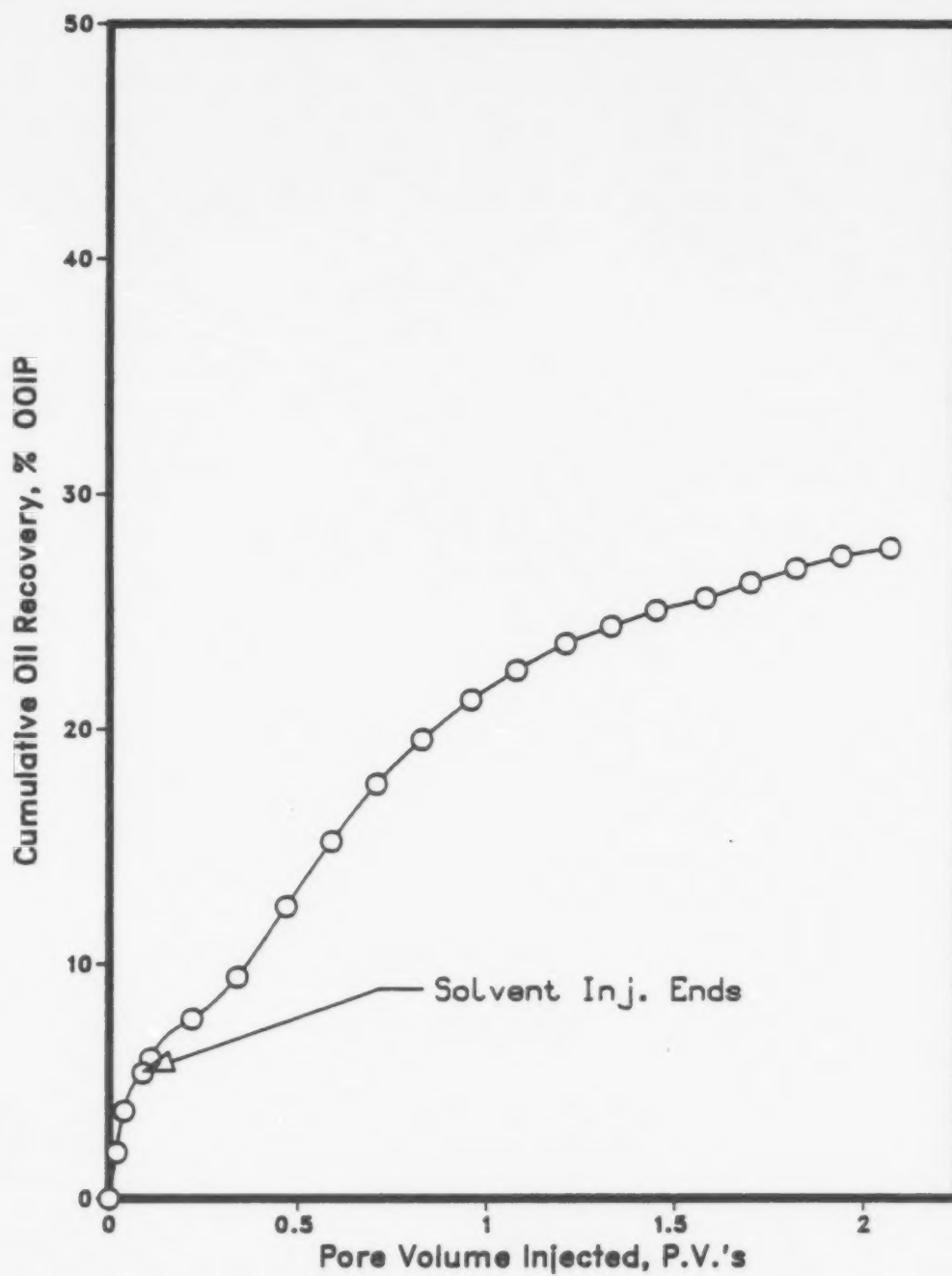


Figure 5.19 :Run 46 Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected

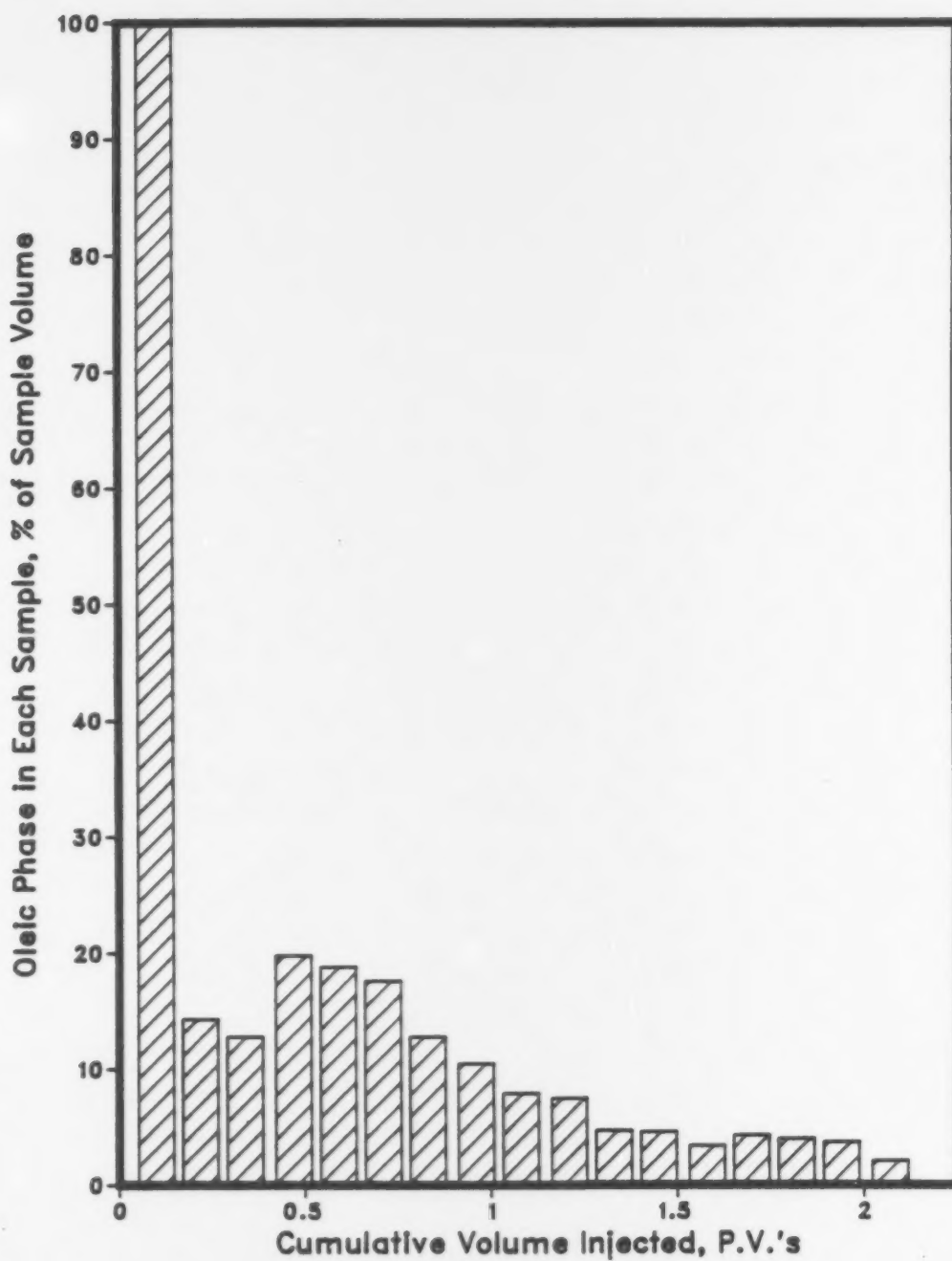


Figure 5.20 :Run 46 Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected

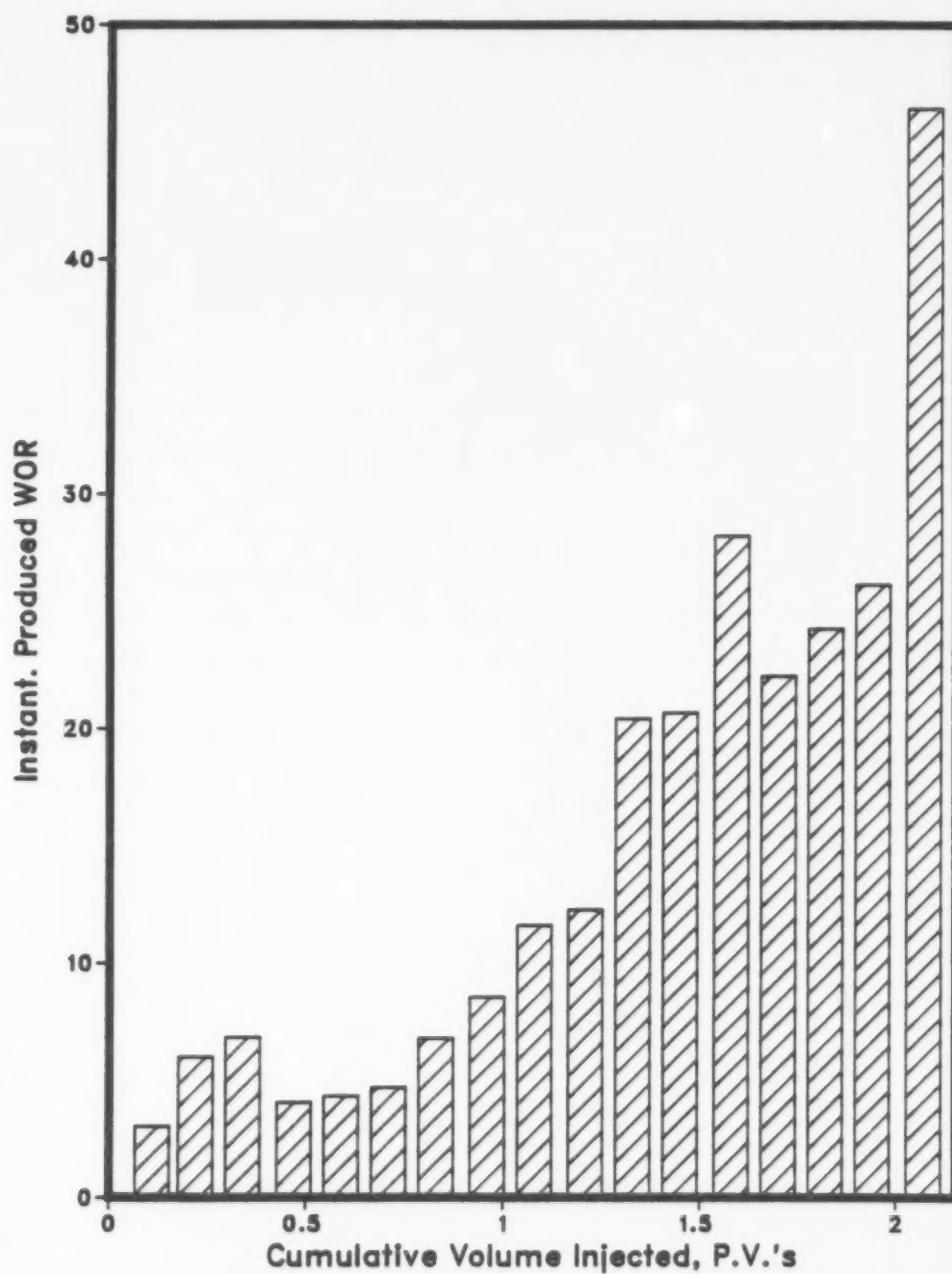
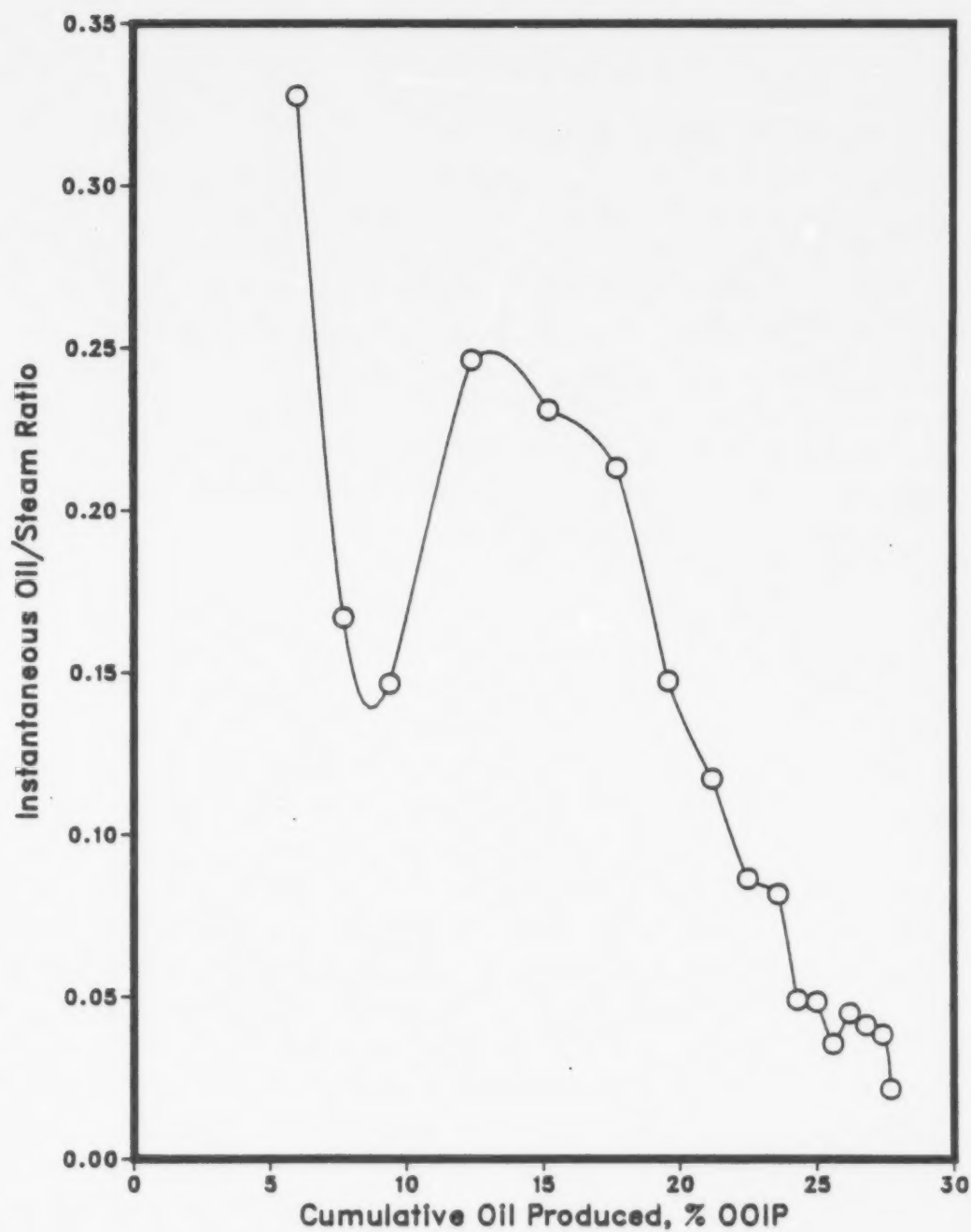


Figure 5.21 :Run 46 Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced



sweeping the model and creating an oil bank. Production of additional oil from the unswept and swept areas was indicated by the gradual decline of the curve after the peak.

Opposite to what occurred in the solvent flood, the top view temperature profiles for Runs 44 (Figures A.23-A.30), 45 (Figures A.35-A.42) and 46 (Figures A.47-A.54) indicate that the steam advanced faster through the upper level of the model than the lower section. The heat also appears to be moving slightly faster in the upper half of the model according to the cross-sectional temperature profiles provided in Figures A.31-A.34 (Run 44), Figures A.43-A.46 (Run 45) and Figures A.55-A.58 (Run 46). The faster heat advance in the upper section of the model was probably due to the gravity segregation behaviour of the steam in which the less dense steam tended to rise in the formation.

During the initial stages of the solvent-steamflood the solvent slug channelled into the oil zone and created a less resistant path for the steam to travel into oil, than would exist by simply injecting steam into an undisturbed oil region. This allowed the steam heat to be used more effectively to mobilize and displace the oil. The mobilized oil and solvent banked up at the production well creating a pressure buildup at the well. Once the banked up oil was produced and steam breakthrough occurred the high temperature steam continued to sweep through the model producing additional oil from both swept and unswept regions. The low solvent recovery of 33.1% in Run 46 is attributed to the higher water saturation in this run, which caused greater trapping of the injected solvent. The solvent recoveries for these runs were much lower than the solvent recovery of the solvent flood because less extensive channelling took place during the solvent-steamfloods and therefore more solvent mixed with the oil. This resulted in more solvent being trapped in the model as a residual hydrocarbon saturation. The three solvent-steamfloods required less solvent than Run 40 which also contributed to the lower solvent recovery. The use of the solvent slug before steam injection in the three solvent-steamflood experiments allowed the steam to contact a large area of oil which resulted in a more stable displacement of oil than in the case of a solvent flood (Run 40).

Oil recoveries for Runs 44 (27.1% OOIP), 45 (30.0% OOIP) and 46 (27.7% OOIP) were higher than that obtained for Run 40 (26.8% OOIP). However, the oil recovery for the solvent-steamfloods was about the same as previous continuous steamfloods such as Runs 26 (31.8% OOIP) and 27 (32.2 % OOIP), reported by Proctor, George and Farouq Ali ⁶³. Therefore using a solvent-steamflood process does not appear to be as economically attractive as a conventional steamflood performed in a homogeneous model. However, in the case of a heavy oil formation without bottom water and displaying a very low steam injectivity the implementation of solvent injection would help to raise steam injectivity. This would make steam penetration more extensive in the oil and therefore increase recovery compared to a conventional steamflood. The use of a solvent-steamflood process in a bottom water formation may also be better suited than a conventional steamflood process, which will be discussed later in this chapter.

Steamflood of a Bottom Water Model With Prior Gas Injection

It is believed that injecting a small portion of inert gas before performing a steamflood, a flow channel would form, which would divert the injected steam away from the bottom water region and into the oil zone. This would aid in minimizing the heat scavenging effects of the bottom water zone. The process of gas injection in combination with a conventional steamflood was first performed in a bottom water model which represents a base experiment.

Runs 60 and 61 investigated oil recoveries of a steamflood performed on a bottom model which contained a gas cap. The recoveries were carefully studied in order to determine the effectiveness of a steamflood in a reservoir containing a gas cap and bottom water layer. Tables 5.7 and 5.8 provide a list of the results for Runs 60 and 61, respectively. Bottom water thicknesses were 17.6% and 12.1% of the gross model thickness for Runs 60 and 61, respectively, and the initial gas saturations were 0.3% and 0.4% for Runs 60 and 61, respectively.

Runs 60 and 61 consisted of creating a gas cap in a bottom water model prior to a conventional steamflood. The gas cap was created by injecting nitrogen gas which displaced a small portion of oil in the model. The volume of the gas cap was considered to be the amount of oil displaced by the gas. Nitrogen gas was chosen since it was an inert gas and therefore would not initiate a chemical reaction in the model during the gas injection experiments. Since the initial gas saturation was relatively small the gas cap developed in the upper portion of the model and probably consisted of a small narrow channel extending from the injection well to the production well.

The recovery curves of Runs 60 (Figure 5.22) and 61 (Figure 5.26) gave an early indication that the presence of a gas cap and bottom water hindered the overall oil recovery. The oil recovery for Run 61 (19.5% OOIP) showed a higher recovery than Run 60 (13.6% OOIP) due to the thinner bottom water zone present in Run 61. The thinner bottom water

layer resulted in less of the steam's heat being scavenged and thus, more oil was mobilized and recovered during Run 61.

The bar plots of volume as a percentage of oleic phase in each sample taken versus cumulative volume injected and instantaneous produced WOR versus cumulative volume injected are provided for Runs 60 (Fig. 5.23 & 5.24) and 61 (Fig. 5.27 & 5.28). The values of instantaneous hydrocarbon produced were relatively low and there was no evidence of a prevalent peak in either of Figures 5.23 or 5.27 indicating that a well defined steam breakthrough did not occur during either experiment. Therefore a very unstable displacement appeared to exist during Runs 60 and 61, as also indicated by Figures 5.24 and 5.28. It was concluded that a majority of the injected steam flowed into the underlying bottom water or passed over the oil region into the gas cap.

The plots of instantaneous oil/steam ratio versus cumulative oil produced are displayed in Figures 5.25 (Run 60) and 5.29 (Run 61). Due to the thicker bottom water zone, Run 60 shows smaller oil/steam ratio values than Run 61. The oil/steam ratio curves in Runs 60 and 61 are quite different. In Run 60, steam clearly displaced the oil efficiently at first, but later breakthrough occurred, and the oil/steam ratio dropped. To a first approximation it can be said that the oil/steam ratio was relatively constant at 0.075. In Run 61, on the other hand, although the oil/steam ratios are generally higher than those in Run 60, the oil/steam ratio steadily drops. Overall the oil/steam ratio values for both experiments were low, which suggested that the underriding of the oil by the injected steam into the bottom water zone was quite prevalent in Runs 60 and 61 due to the lack of steam penetration into the oil layer.

Study of the temperature profiles for Runs 60 (Fig. A.59-A.66) and 61 (Fig. A.71-A.78) revealed that the injected heat advanced much more quickly through the lower region of the model due to the steam underriding the oil layer into the bottom water. The cross-sectional temperature profiles given in Figures A.67-A.70 (Run 60) and Figures A.79-

Table 5.7 : Run 60 Gas Injection Prior to Steamflood of Bottom Water Model

HC Pore Volume :	11500.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15080.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	35.9%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	76.3%	Total Flow Rate of Steam :	229.20 cc/min
Initial H ₂ O Satn. :	23.4%	Gas Cap Volume :	50.0 cc
Initial Gas Satn. :	0.3%	Steam Vol. Inj. :	34850.0 cc (2.31 PV)
		Bottom Water Layer Thickness :	17.6% (% Gross Thickness)

Net Oil Recovery : 13.6 %

Final Oil Saturation : 65.9 %

Cyl. No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. Oil Prod. % of Sample
1	1980	1980	65	65	0.6%	29.46	3.3%
2	2195	4175	15	80	0.7%	45.00	0.7%
3	1960	6135	45	125	1.1%	42.56	2.3%
4	2210	8345	60	185	1.6%	35.83	2.7%
5	2030	10375	145	330	2.9%	13.00	7.1%
6	2030	12405	140	470	4.1%	13.50	6.9%
7	1990	14395	130	600	5.2%	14.31	6.5%
8	2025	16420	120	720	6.3%	15.88	5.9%
9	2000	18420	120	840	7.3%	15.67	6.0%
10	2135	20555	105	945	8.2%	19.33	4.9%
11	2065	22620	60	1005	8.7%	33.42	2.9%
12	2095	24715	135	1140	9.9%	14.52	6.4%
13	1985	26700	105	1245	10.8%	17.90	5.3%
14	2070	28770	85	1330	11.6%	23.35	4.1%
15	2005	30775	80	1410	12.3%	24.06	4.0%
16	2095	32870	75	1485	12.9%	26.93	3.6%
17	1980	34850	80	1565	13.6%	23.75	4.0%

**Figure 5.22 :Run 60 Gas Injection Prior to Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected**

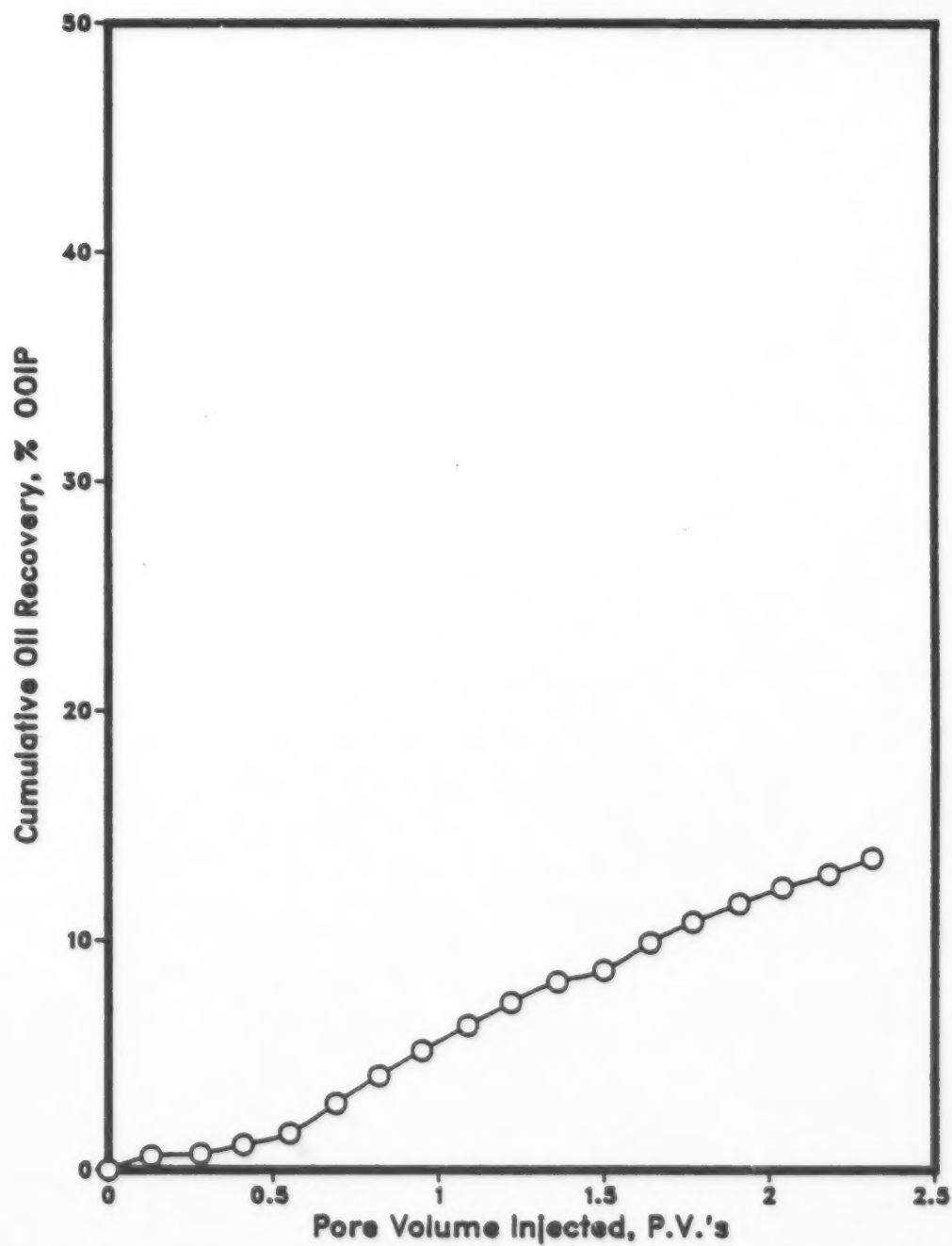


**Figure 5.23 :Run 60 Gas Injection Prior to Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

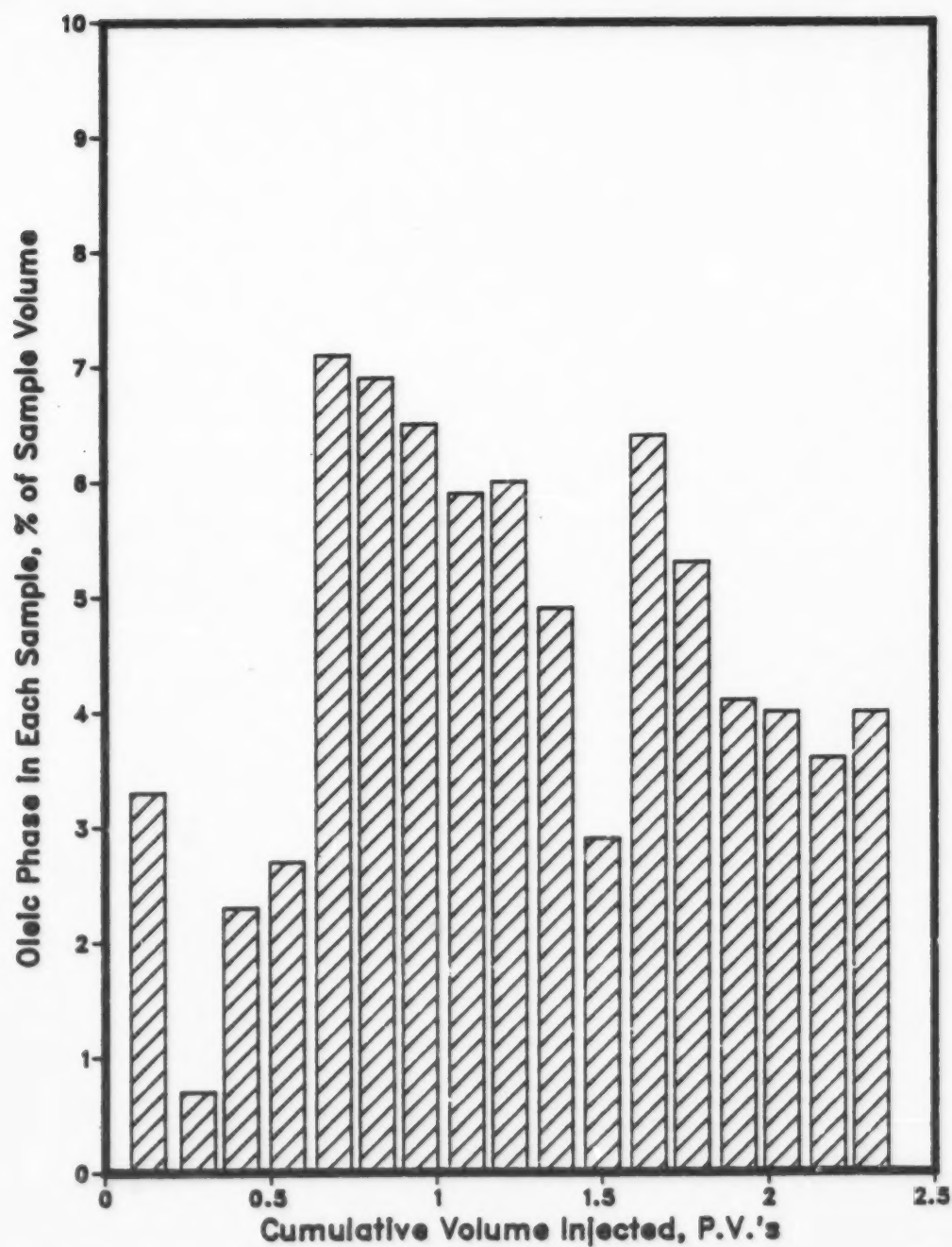


**Figure 5.24 :Run 60 Gas Injection Prior to Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

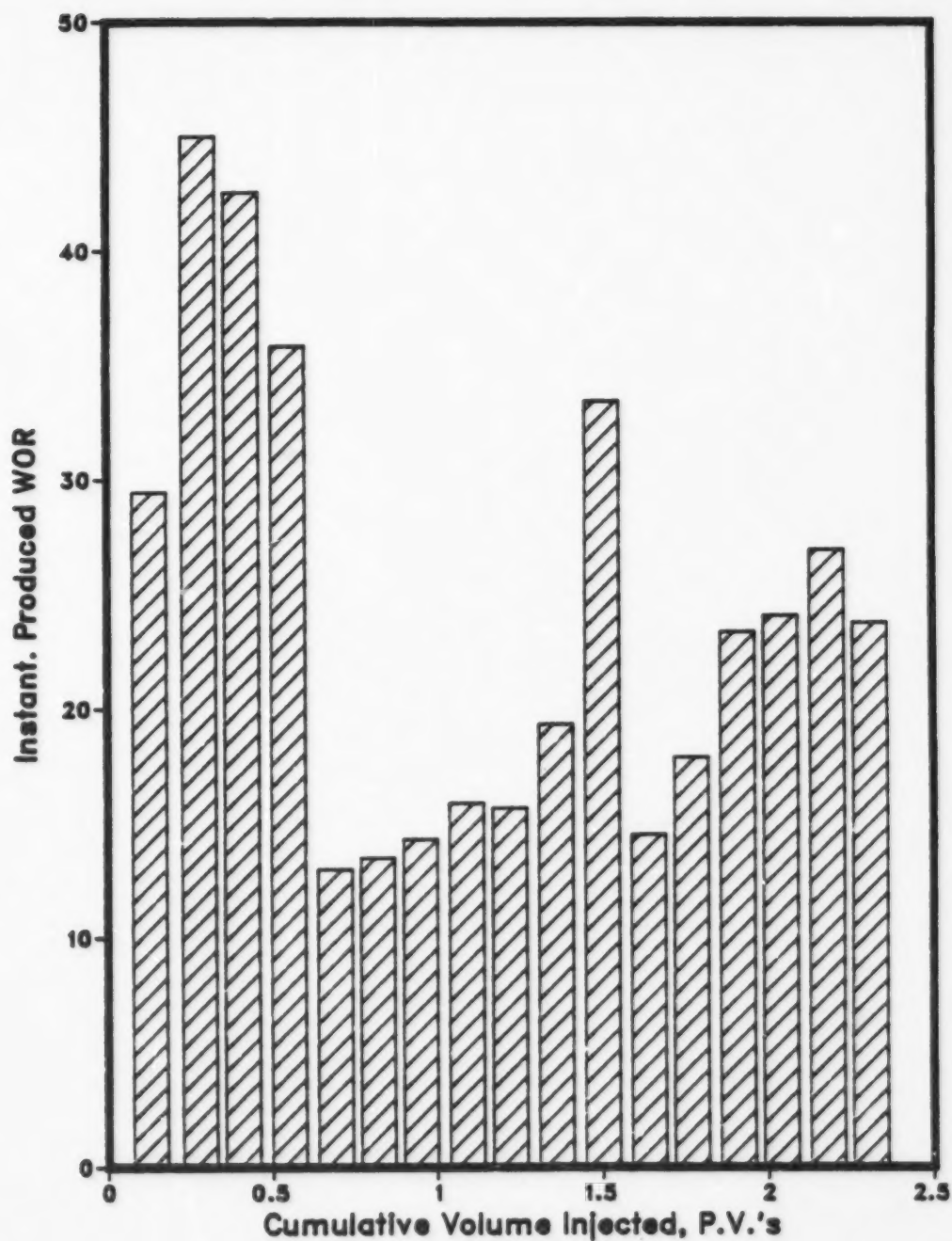


Figure 5.25 :Run 60 Gas Injection Prior to Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

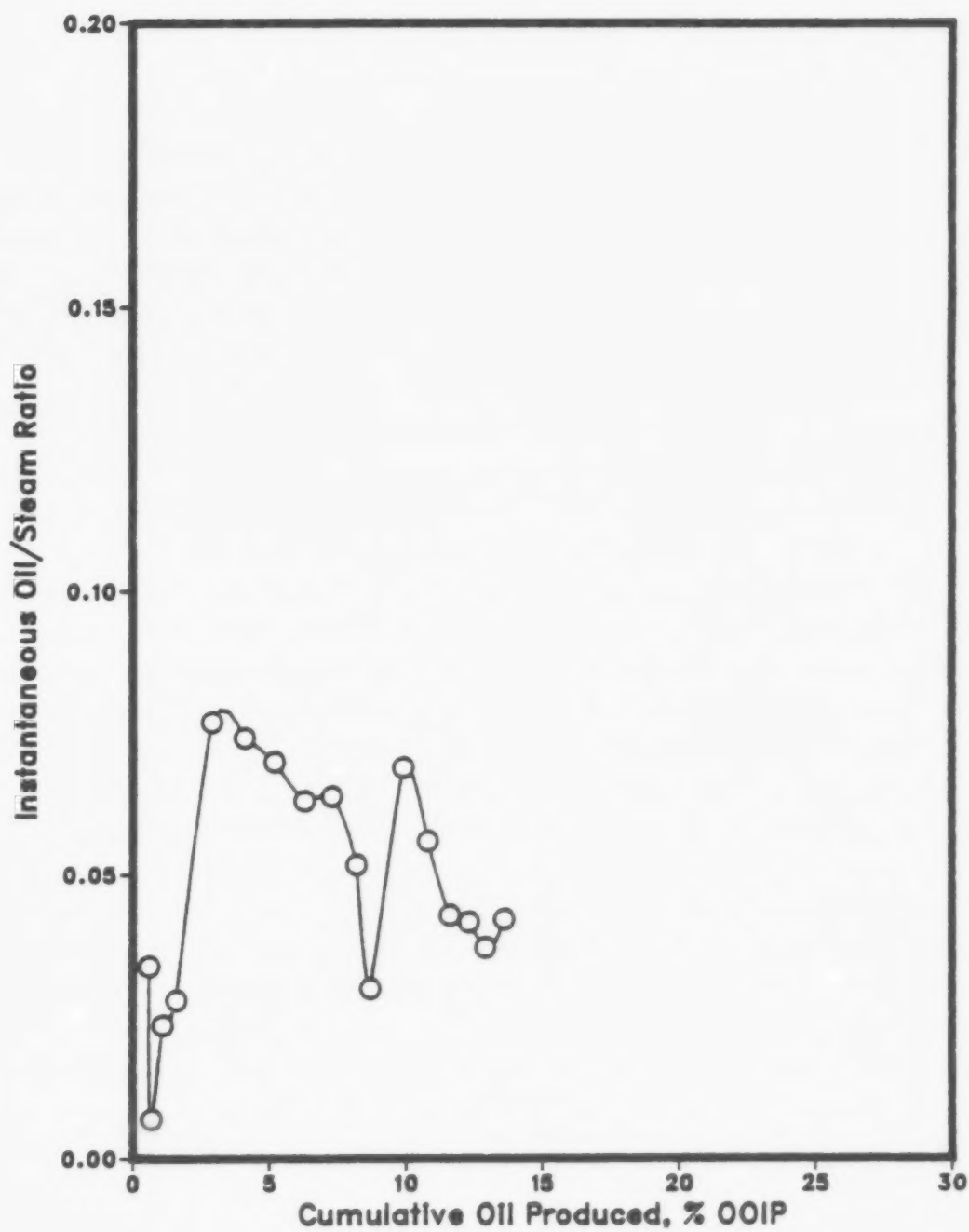


Table 5.8 : Run 61 Gas Injection Prior to Steamflood of Bottom Water Model

HC Pore Volume :	12615.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15115.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	36.0%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	83.5%	Total Flow Rate of Steam :	229.20 cc/min
Initial H2O Satn. :	16.2%	Gas Cap Volume :	55.0 cc
Initial Gas Satn. :	0.4%	Steam Vol. Inj. :	34800.0 cc (2.30 PV)
		Bottom Water Layer Thickness :	12.1% (% Gross Thickness)

Net Oil Recovery : 19.5%

Final Oil Saturation : 67.2%

Cyl. No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj.		Oil Prod. (cc)	Cum. Oil Rec.		Oil-Steam Ratio	Inst Prod. WOR	Inst. Oil Prod. % of Sample
		(cc)	(P.V.)		(cc)	(%OOIP)			
1	1850	1850	0.12	260	260	2.1%	0.1635	6.12	14.1%
2	2180	4030	0.27	145	405	3.2%	0.0713	14.03	6.7%
3	2055	6085	0.40	225	630	5.0%	0.1230	8.13	10.9%
4	2020	8105	0.54	195	825	6.5%	0.1068	9.36	9.7%
5	2025	10130	0.67	185	1010	8.0%	0.1005	9.95	9.1%
6	2060	12190	0.81	160	1170	9.3%	0.0842	11.88	7.8%
7	1985	14175	0.94	160	1330	10.5%	0.0877	11.41	8.1%
8	2065	16240	1.07	145	1475	11.7%	0.0755	13.24	7.0%
9	1995	18235	1.21	135	1610	12.8%	0.0726	13.78	6.8%
10	2360	20595	1.36	120	1730	13.7%	0.0536	18.67	5.1%
11	1940	22535	1.49	125	1855	14.7%	0.0689	14.52	6.4%
12	2085	24620	1.63	105	1960	15.5%	0.0530	18.86	5.0%
13	1985	26605	1.76	85	2045	16.2%	0.0447	22.35	4.3%
14	2175	28780	1.90	160	2205	17.5%	0.0794	12.59	7.4%
15	1980	30760	2.04	80	2285	18.1%	0.0421	23.75	4.0%
16	2070	32830	2.17	90	2375	18.8%	0.0455	22.00	4.3%
17	1970	34800	2.30	85	2460	19.5%	0.0451	22.18	4.3%

Figure 5.26 Run 61 Gas Injection Prior to Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

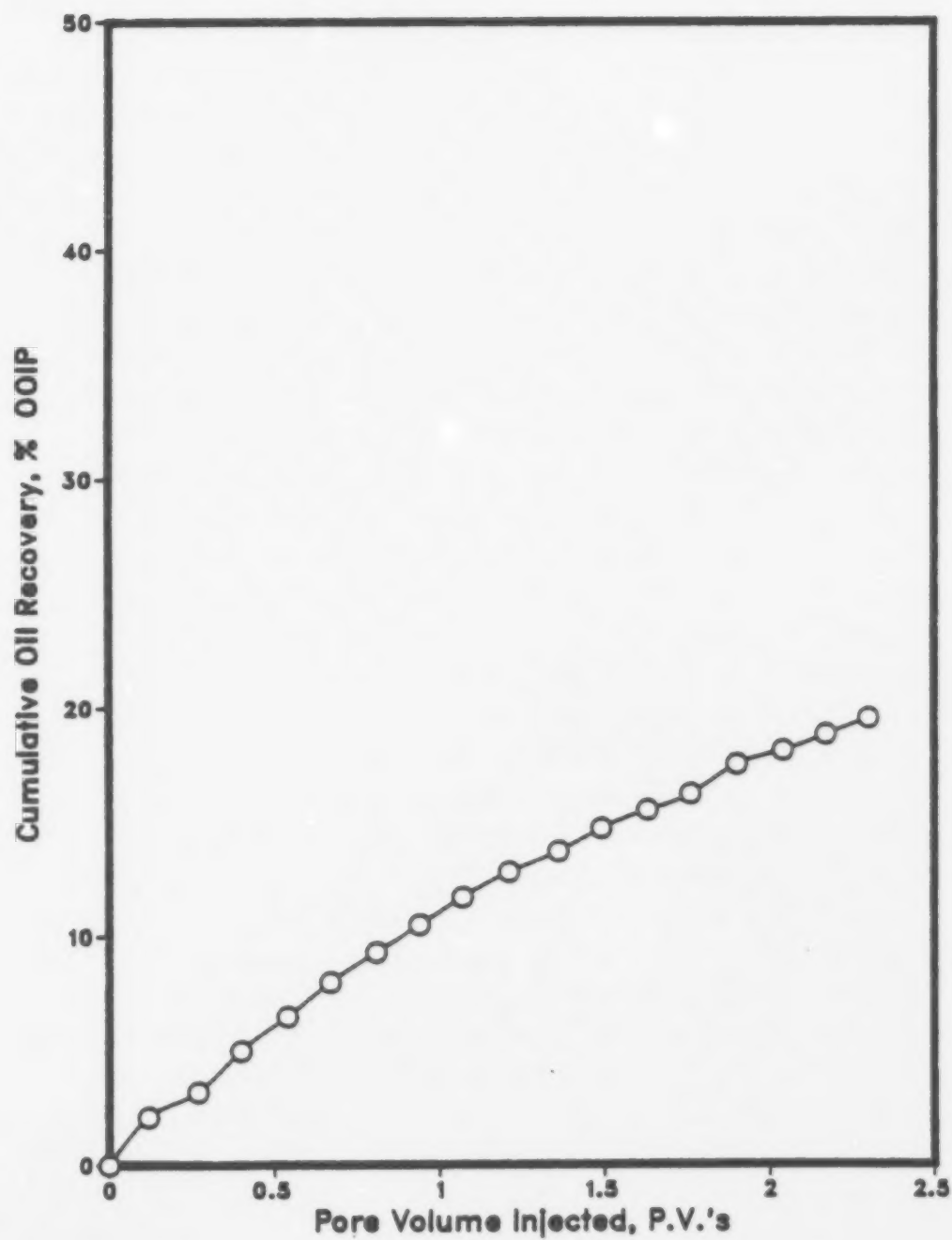


**Figure 5.27 :Run 61 Gas Injection Prior to Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

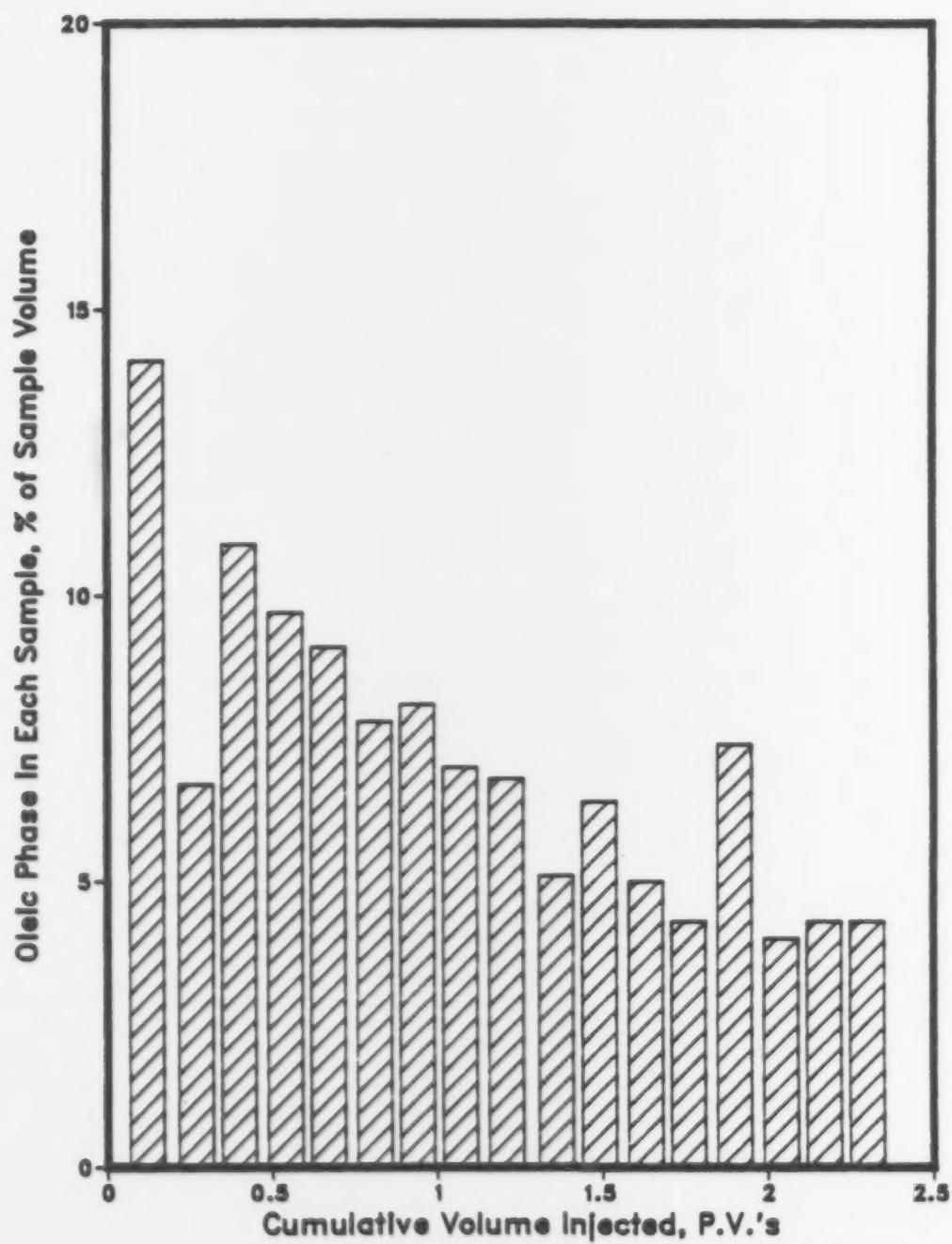


**Figure 5.28 :Run 61 Gas Injection Prior to Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

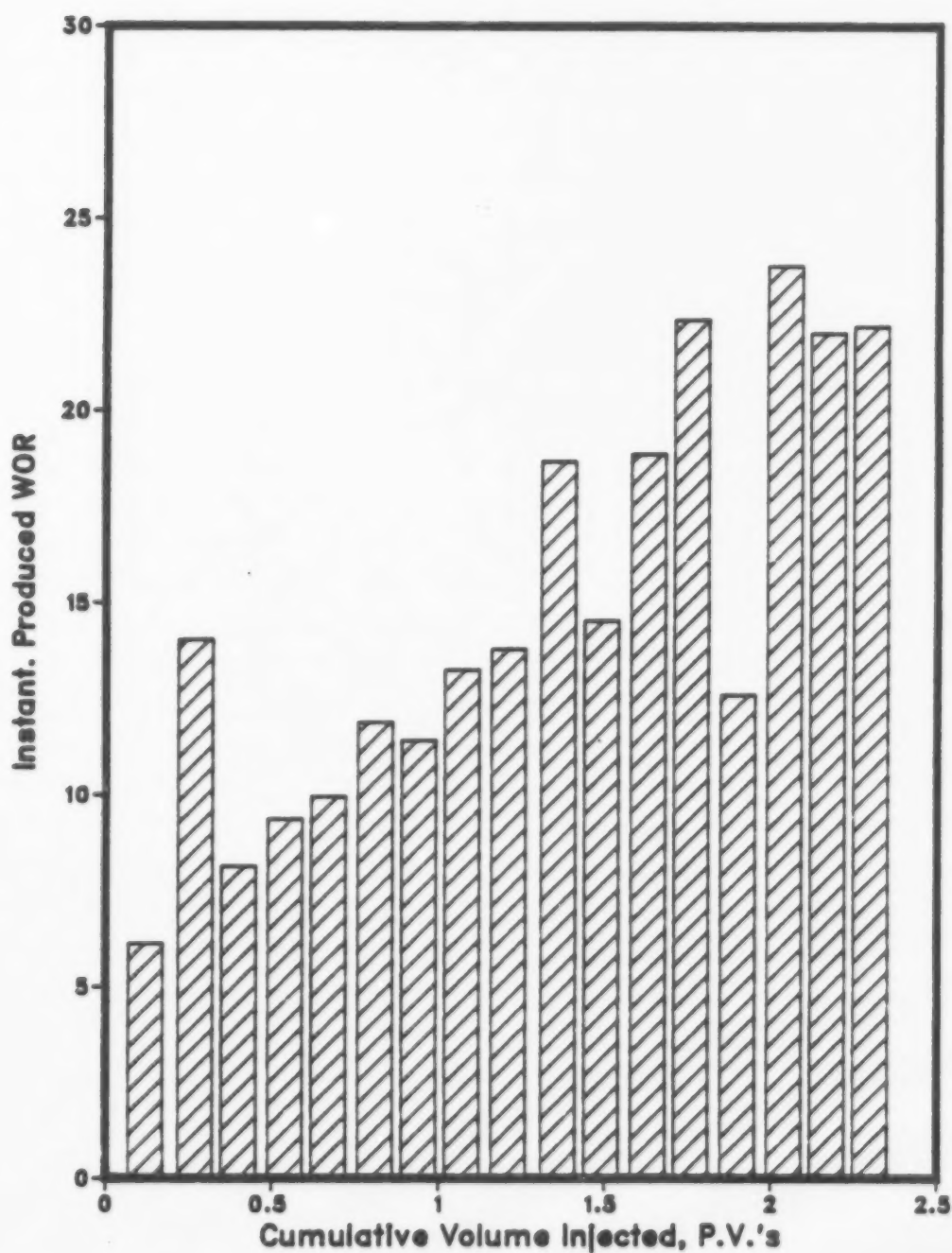
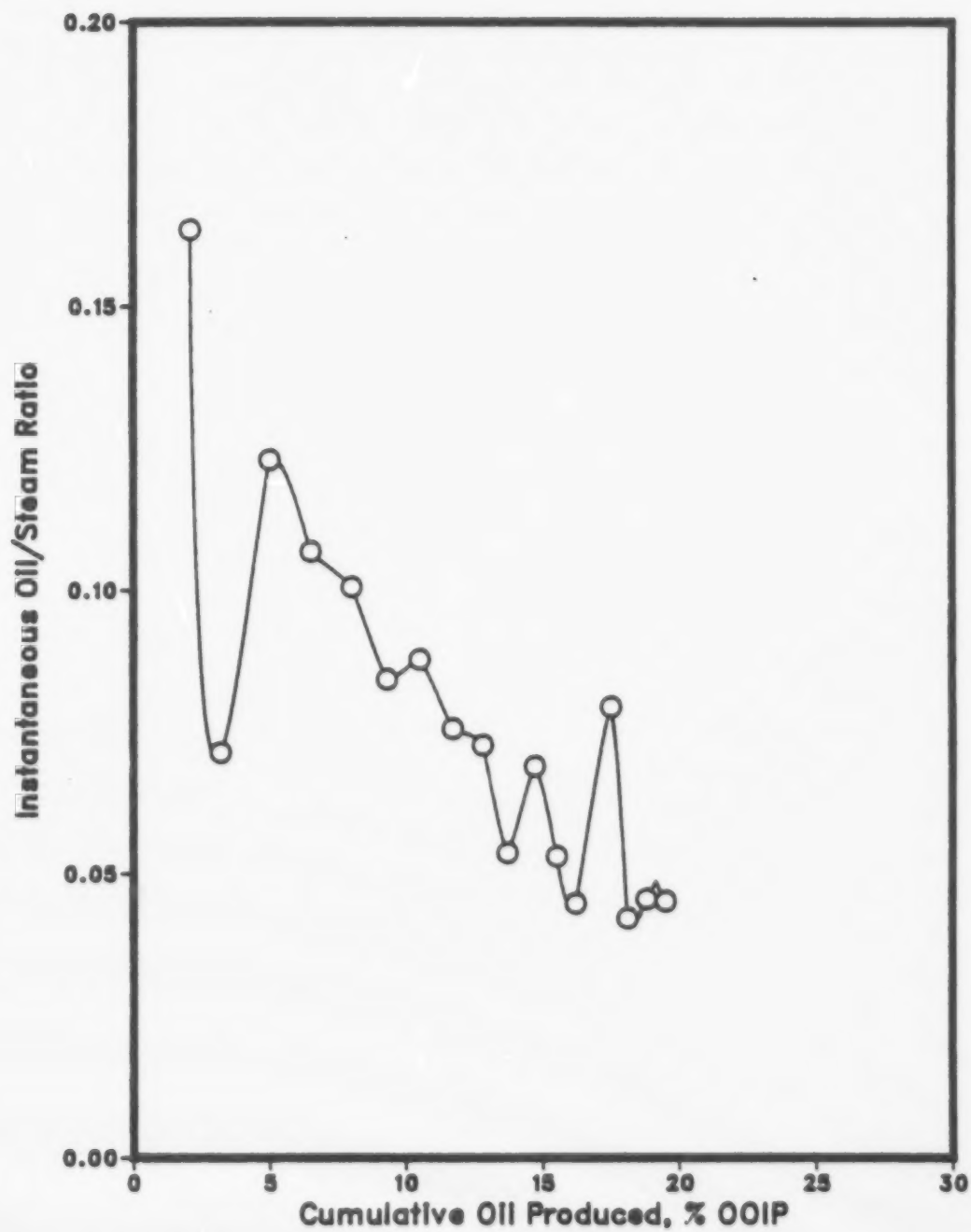


**Figure 5.29 :Run 61 Gas Injection Prior to Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced**

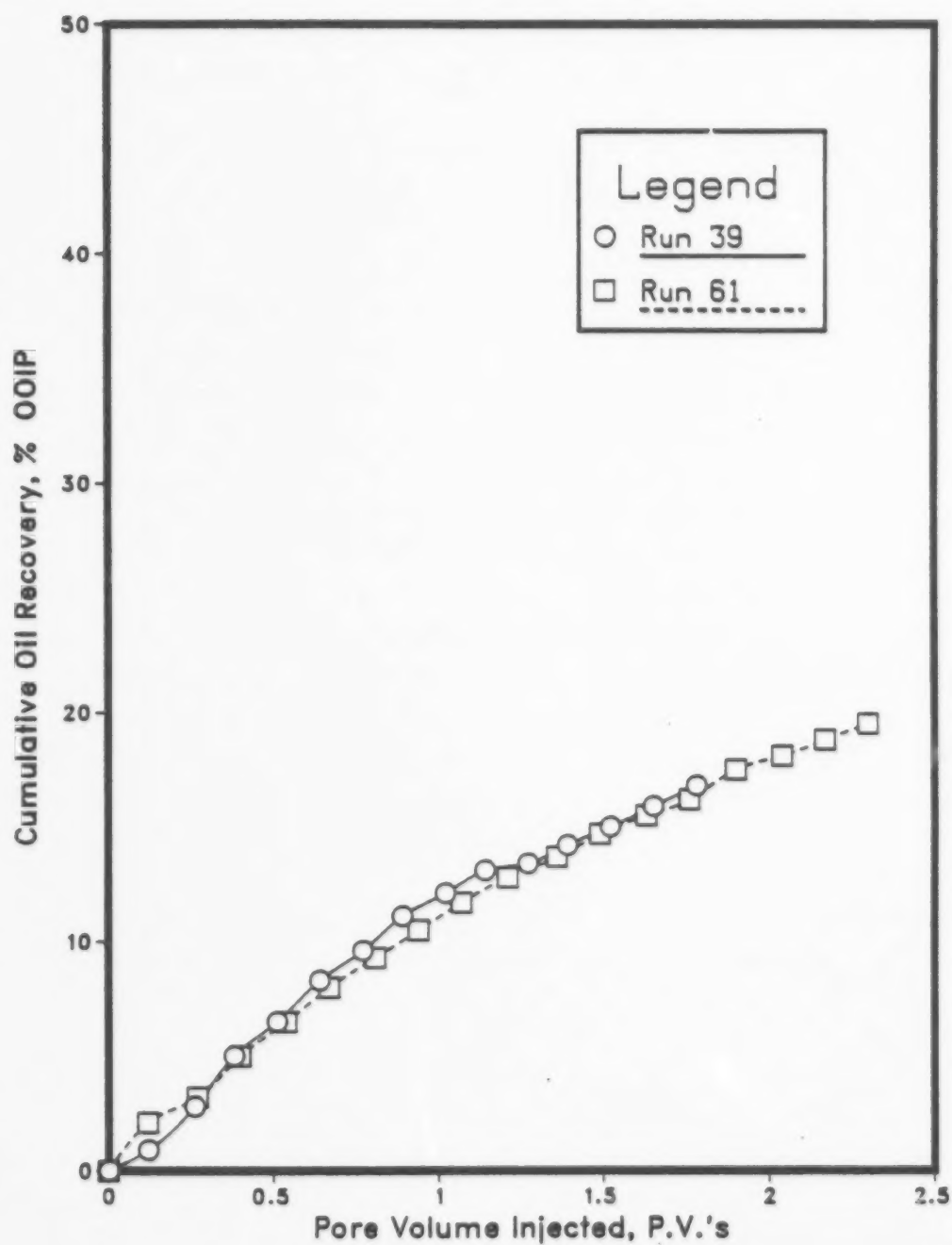


A.82 (Run 61) illustrate the prevalent heat scavenging nature of the bottom water since the heat appeared to travel faster in the lower section of the model.

It was concluded from the results of Runs 60 and 61 that the presence of a gas cap during a steamflood of a bottom water model tended to partially divert the steam away from the bottom water so that it could be used more effectively to heat up and mobilize the oil region. Comparison of the recoveries (Figure 5.30) of Run 39, a conventional steamflood, and Run 61, a steamflood preceded by gas injection, which had similar bottom water thicknesses, indicated that the presence of a gas cap somewhat improved the initial recovery response of a steamflood performed in a bottom water model. Also a comparison of the other plots generated for Runs 39 and 61 indicated steam breakthrough occurred sooner and was less distinct in the case of Run 39, which again confirmed that the implementation of a gas cap has the potential to improve the oil recovery during the steamflood of a bottom water formation.

From the results of Runs 60 and 61 the implementation of a solvent-steamflood process in a model with a gas cap and bottom water may further improve oil recovery by partially diverting more injected steam away from the detrimental bottom water zone.

Figure 5.30 : Comparison of Steamflood Run 39 & Gas Injection Prior to a Steamflood Run 61 Recoveries Performed in a Bottom Water Model



Effect of Solvent Slug Size on Oil Recovery by a Steamflood

It was important in this study to determine the effect of different solvent slug sizes on the overall oil recovery of a solvent-steamflood process. By determining the effect of solvent slug size, an optimal slug size might be established in order to increase oil recovery of a solvent-steamflood process.

Run 65 was conducted to investigate the effect of varying the amount of solvent injected into a bottom water model prior to steamflooding. The experiment involved doubling the solvent slug size from 10% of the model pore volume to 20%. The bottom water layer in the model was thick (19.6% of the gross model thickness). The results of Run 65 are provided in Table 5.9.

The oil recovery yielded in Run 65 was 19.8% of the original oil in place. The recovery curve of Run 65 is given in Figure 5.31. Runs 53 and 54 involved solvent-steamfloods of bottom water models with reasonably thick bottom water thicknesses of 15.2% and 12.2% of the gross model thickness, respectively and a solvent slug size of 10% of the model pore volume. These two similar experiments were compared with Run 65 in order to determine the effect of a larger solvent slug. The shape of the curve in Figure 5.31 was similar to that of the recovery curves obtained in Runs 53 and 54 even though Run 65 had a greater bottom water thickness. This suggested that the increase in the solvent slug size to 20% of the model pore volume somewhat improved the overall oil recovery. Due to the thick bottom water layer, the loss of injected solvent to the bottom water was prevalent, explaining the solvent recovery of 73.0%. However, solvent recovery was still comparable to the solvent recoveries of Runs 53 and 54 which were 54.4% and 89.8%, respectively.

The bar plots of volume as a percentage of oleic phase in each sample collected versus cumulative volume injected and instantaneous produced WOR versus cumulative volume injected are provided for Run 65 (Fig. 5.32 & 5.33). It was observed from

Figures 5.32 and 5.33 that Run 65 required longer for steam breakthrough to occur, compared to the steam breakthrough times for Runs 53 and 54. The longer steam breakthrough time was probably due to the larger solvent slug used which mobilized and displaced more of the in-place oil than the 10% solvent slug run. Therefore a larger volume of solvent and oil banked up at the production well. Steam breakthrough was prolonged because of the larger oil/solvent bank at the production well which required longer to be produced.

The plot of instantaneous oil/steam ratio versus cumulative oil produced for Run 65 is provided in Figure 5.34. Comparing the similar plots of Runs 53 and 54 it was noted that the initial values of oil/steam ratio in Figure 5.34 were much larger than the initial oil/steam ratio values for Runs 53 and 54. This suggested, as did the previously discussed bar plots (Figures 5.32 & 5.33), that a larger oil/solvent bank formed at the production well during Run 65. It seems that one-half of the oil is displaced very efficiently with large oil/steam ratios. Following that steam seems to channel into the water and recovery slows down. As more oil was produced the oil/steam ratios of Figure 5.34 dropped until they were less than the later oil/steam ratio values for Runs 53 and 54. The thicker bottom water layer present in Run 65 appeared to be more prevalent during the final stages of the experiment.

The temperature profiles for Run 65 are given in Figures A.83-A.90. Careful examination of the temperature profiles revealed that the injected heat travelled at about the same rate in both the upper and lower sections of the model during Run 65 as compared to Runs 53 and 54, despite the thicker bottom water layer of Run 65. This would indicate that the larger solvent slug created more extensive channels in the oil zone allowing the injected steam to be more efficiently used throughout the oil region instead of being lost to the bottom water. The cross-sectional temperature profiles in Figures A.91 through A.94 also indicate this.

Table 5.9 : Run 65 Solvent-Steamflood With Bottom Water

HC Pore Volume :	11140.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15180.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	36.1%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	73.4%	Total Flow Rate of Steam :	229.20 cc/min
Initial H ₂ O Satn. :	26.6%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	2800.0 cc (20.0% PV)	Bottom Water Layer Thickness :	19.6 % (% Gross Thickness)
Steam Vol. Inj. :	32005.0 cc (2.09 PV)		

Net Oil Recovery : 19.8 %				Solvent Recovery : 73.0 %				Final Oil Saturation : 58.9 %			
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Solvent Ratio	Inst. H.C Prod. % of Sample
1	0%	1400	1400	0.09	25	25	0.2%	0	0.0%	0.0182	55.00
2	69%	1205	2605	0.17	845	262	2.6%	583	20.8%	2.3472	0.43
3	82%	1500	4105	0.27	1095	197	4.3%	1481	52.9%	2.7037	0.37
4	53%	1705	5810	0.38	795	374	7.7%	1902	67.9%	0.8736	1.14
5	30%	2050	7860	0.52	235	165	9.2%	1972	70.4%	0.1295	7.72
6	21%	2025	9885	0.65	130	103	10.1%	1999	71.4%	0.0686	14.58
7	16%	2135	12020	0.79	45	38	10.4%	2006	71.6%	0.0215	46.44
8	12%	2205	14225	0.94	55	48	10.9%	2013	71.9%	0.0256	39.09
9	11%	2120	16345	1.08	70	62	11.4%	2021	72.2%	0.0341	29.29
10	9%	2000	18345	1.21	105	96	12.3%	2030	72.5%	0.0554	18.05
11	6%	1940	20285	1.34	105	99	13.2%	2036	72.7%	0.0572	17.48
12	3%	2075	22360	1.47	100	97	14.1%	2039	72.8%	0.0506	19.75
13	2%	1955	24315	1.60	105	103	15.0%	2041	72.9%	0.0568	17.62
14	1%	2055	26370	1.74	135	134	16.2%	2042	72.9%	0.0703	14.22
15	1%	2080	28450	1.87	115	114	17.2%	2043	73.0%	0.0585	17.09
16	0%	2190	30640	2.02	95	95	18.1%	2043	73.0%	0.0453	22.05
17	0%	1985	32625	2.15	95	95	18.9%	2043	73.0%	0.0503	19.89
18	0%	2180	34805	2.29	95	95	19.8%	2043	73.0%	0.0456	21.95

**Figure 5.31 :Run 65 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected**

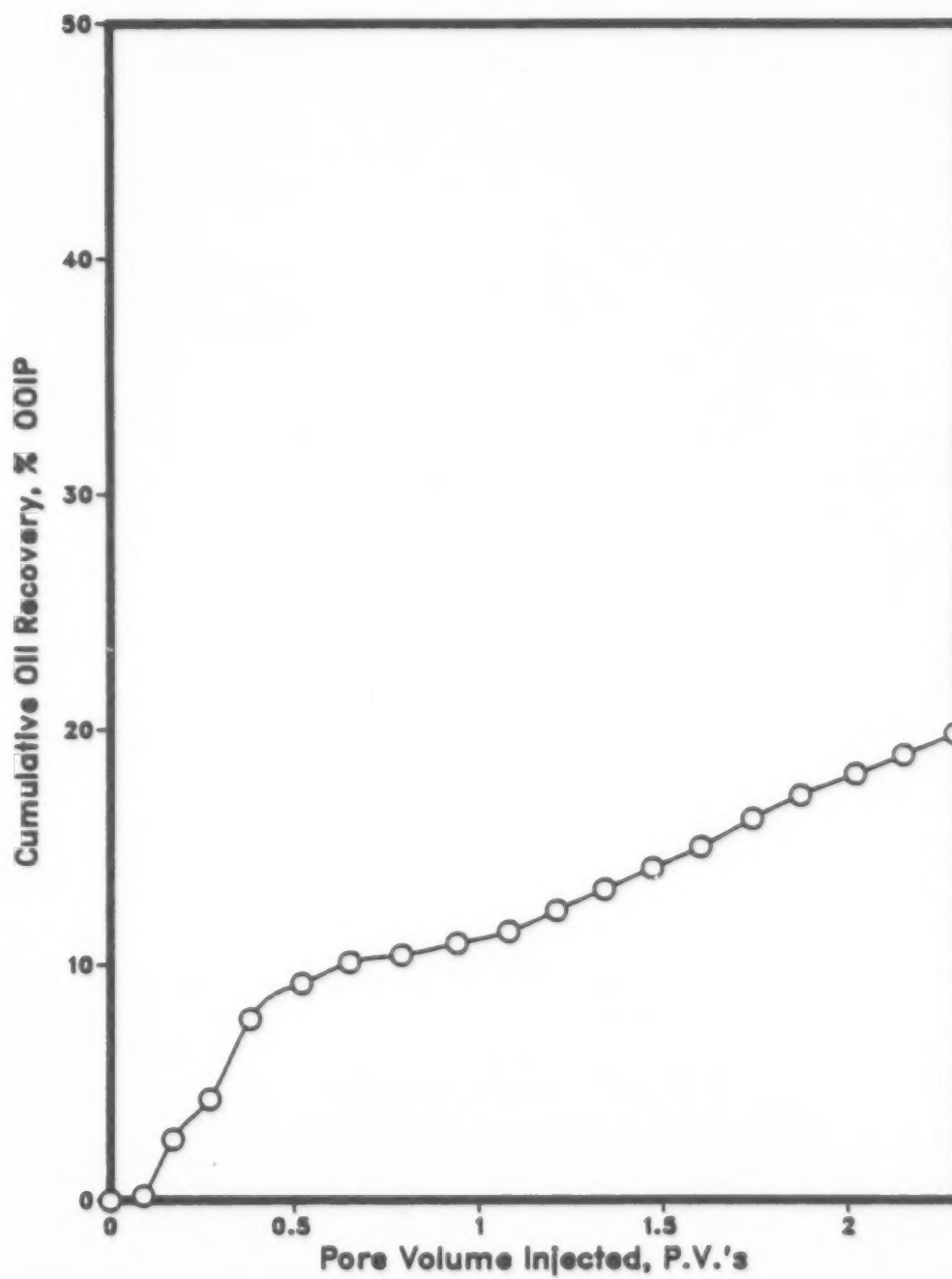


Figure 5.32 :Run 65 Solventflood—Steamflood With Bottom Water
Oleic Phase In Each Sample Vs. Cumulative Volume Injected

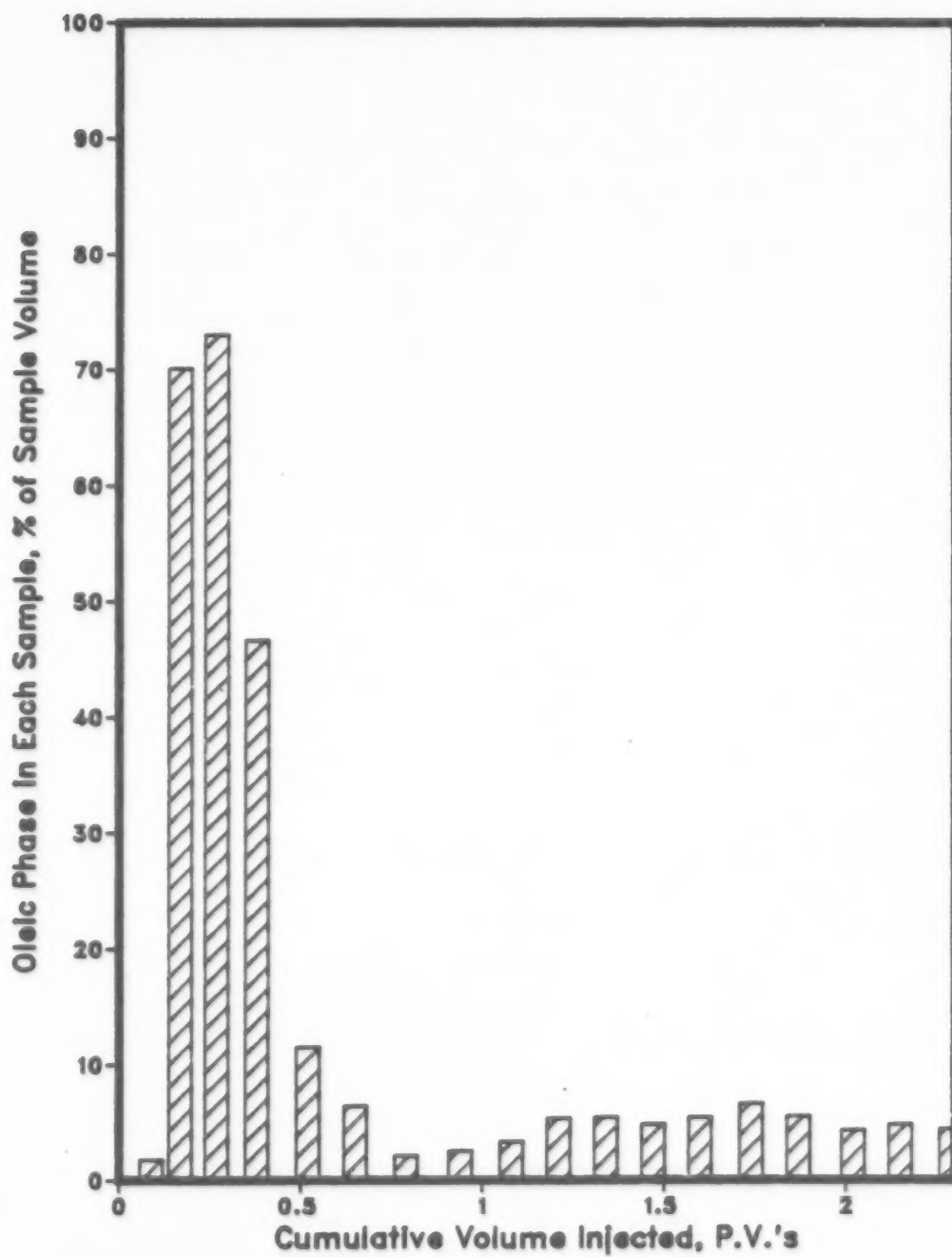


Figure 5.33: Run 65 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected

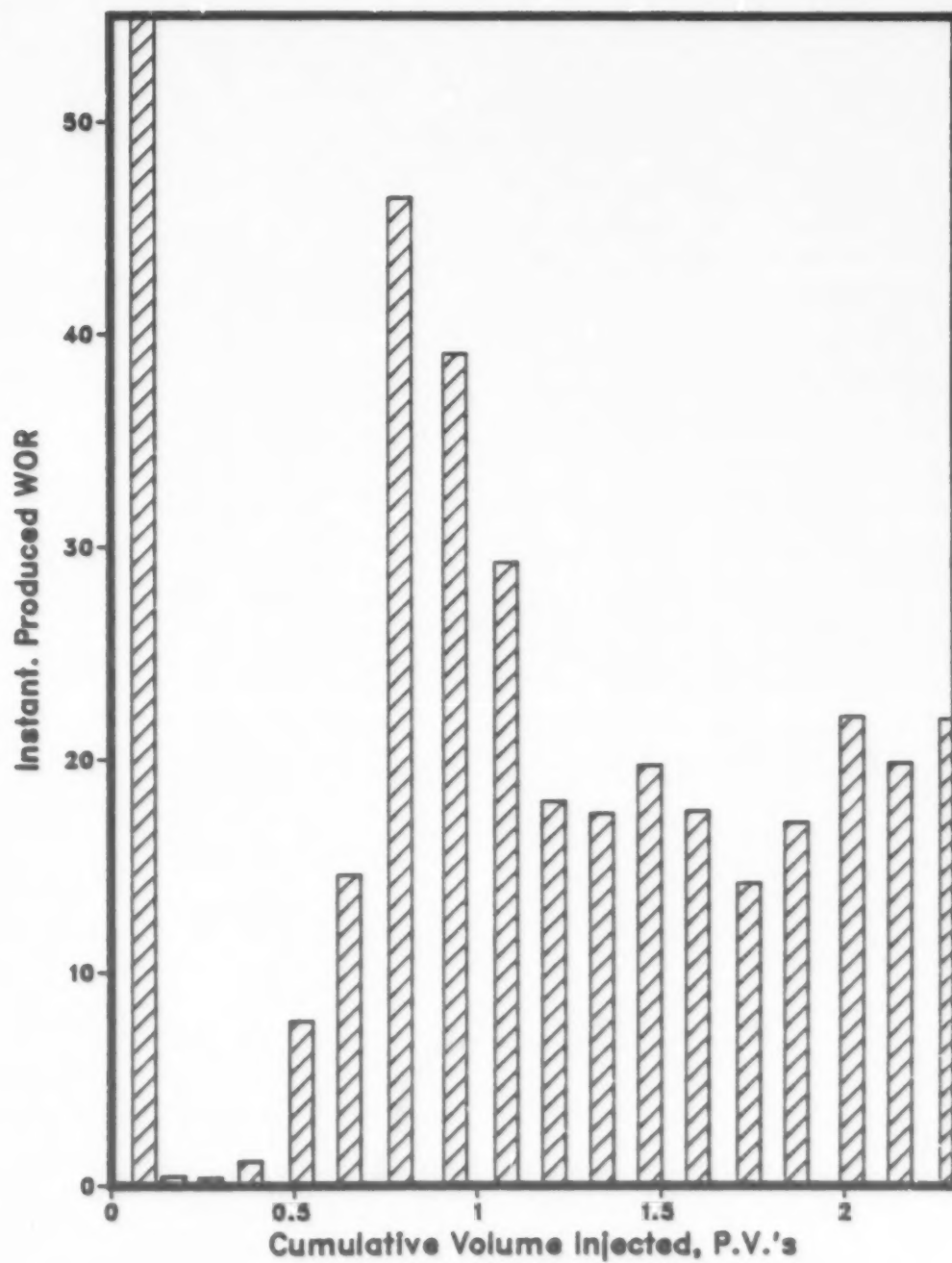
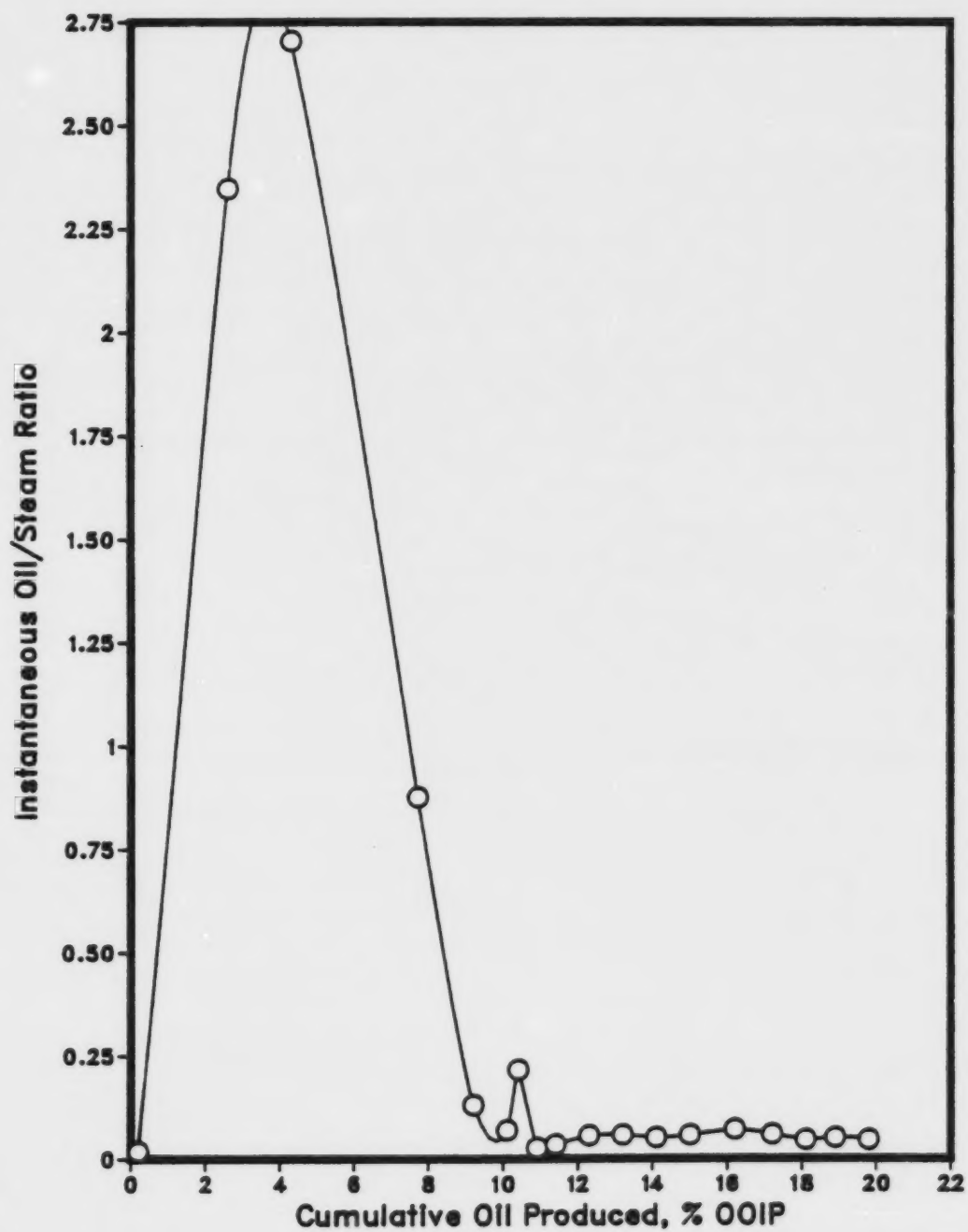


Figure 5.34 :Run 65 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced



A comparison of the results of Run 65 with those of Runs 53 and 54 indicates that increasing solvent slug size may be beneficial to the overall oil recovery. However, one must also consider the extra cost of using additional solvent. This points to an optimal solvent slug size that would produce enough additional oil from the reservoir to warrant the additional expense of using more solvent in the recovery process.

It was decided to use homogeneous models instead of bottom water models, in the further examination of the effect of solvent slug size on recovery, so as to provide more consistent initial model conditions. In the case of the bottom water models the bottom water thicknesses could vary appreciably from one experiment to another, and thus the homogeneous models offered better reproducibility of initial model conditions than the bottom water models. The experimental results of the homogeneous model runs would therefore be more representative of the effect of solvent slug size.

Runs 66, 45 and 67 used solvent slug sizes of 5, 10 and 15% of the total pore volume, respectively. The three experiments involved solvent-steamfloods of a homogeneous model with varying solvent slug sizes. The results of Runs 66, 67 and 45 are provided in Tables 5.10, 5.11 and 5.5, respectively.

Analysis of the recovery curves for Runs 66 (Figure 5.35), 67 (Figure 5.39) and 45 (Figure 5.14) indicate that the experiment implementing the 10% solvent slug (Run 45) provided the best recovery. The recoveries for the 5% (Run 66) and 15% (Run 67) solvent slug experiments were 24.2% OOIP and 25.9% OOIP, which were somewhat less than that obtained in Run 45 (30.0% OOIP).

The bar plots of the amount of oleic phase in each sample as a percentage of each sample volume versus cumulative volume injected and instantaneous produced WOR versus cumulative volume injected are provided for Runs 66 (Fig. 5.36-5.37), 67 (Fig. 5.40-5.41) and 45 (Fig. 5.15-5.16). Figures 5.40 (Run 67) and 5.15 (Run 45) exhibited similar behaviours. The same plot for Run 66 (Figure 5.36) displayed less favorable behaviour than Figures 5.40 and 5.15 due to the smaller solvent (5%) used. The steam

breakthrough for Run 66 occurred sooner and was not clear since a smaller oil/solvent bank formed due to less solvent injected. This caused the hydrocarbon bank to be produced more quickly and resulted in early steam breakthrough. Run 45 displayed a slightly more stable steam displacement of oil than Run 67 (ie. longer time until steam breakthrough and a more distinct breakthrough), which explains the higher recovery yielded by Run 45. The WOR bar plots also indicate a more stable displacement for Run 45 (Figure 5.16) compared to Runs 66 (Figure 5.37) and 67 (Figure 5.41). The displacement in Run 67 (15% solvent slug) appears to be only slightly less stable than for Run 45 from observation of Figures 5.41 and 5.16.

The plots of instantaneous oil/steam ratio versus cumulative oil produced for Runs 66 (Figure 5.38), 67 (Figure 5.42) and 45 (Figure 5.17) suggest that Run 45 was the most effective displacement, followed by Run 67, and finally Run 66 was the least stable displacement of the three experiments.

The top view temperatures profiles for Runs 66 (Fig. A.95-A.102), 67 (Fig. A.107-A.114) and 45 (Fig. A.35-A.42) all indicated that the heat advanced through both the upper and lower sections of the model at about the same rate for all three experiments. Observation of Figures A.35-A.42 for Run 45 indicated that the heat was retained in the upper region of the model for a longer period than it was during Runs 66 and 67. This suggested that the 10% solvent slug used in Run 45 formed more effective channels in the oil zone for the steam to penetrate and mobilize the inplace oil. Comparison of the cross-sectional profiles for Runs 66 (Fig. A.103-A.106), 67 (Fig. A.115-A.118) and 45 (Fig. A.43-A.46) also pointed out that the heat remained in the upper portion of the model longest during Run 45.

The solvent recoveries yielded for Runs 66, 45 and 67 were 91.4%, 71.2% and 97.0%, respectively, which are quite reasonable recovery values.

As reported by Alikhan⁶⁴ the use of a 10% solvent slug prior to steam injection provided the best oil recovery compared to the 5% and 15% solvent slug runs. A

Table 5.10 Run 66 Solvent-Steamflood With Homogeneous Model

HC Pore Volume :	13120.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	14060.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	213.60 cc/min
Porosity :	33.5%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	93.3%	Total Flow Rate of Steam :	242.80 cc/min
Initial H ₂ O Satn. :	6.7%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	700.0 cc (5.0% PV)	Steam Vol. Injected :	35780 cc (2.55 PV)

Net Oil Recovery : 24.2% Solvent Recovery : 91.4% Final Oil Saturation : 70.8%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (P.V.)		HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)		Cum. Sol. Rec. (cc)	Oil-Sol. Rec. (%)		Oil-Sol. Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
			(cc)	(P.V.)			(cc)	(%OOIP)		(cc)	(%)			
1	54%	1780	1780	0.13	855	393	393	3.0%	462	66.0%	0.0000	1.08	1.08	48.0%
2	20%	2020	3800	0.27	325	260	653	5.0%	527	75.3%	0.1917	5.22	5.22	16.1%
3	8%	1980	5780	0.41	320	294	947	7.2%	553	79.0%	0.1928	5.19	5.19	16.2%
4	7%	2110	7890	0.56	355	330	1277	9.7%	578	82.6%	0.2023	4.94	4.94	16.8%
5	6%	1945	9835	0.70	300	282	1559	11.9%	596	85.1%	0.1824	5.48	5.48	15.4%
6	5%	2035	11870	0.84	230	219	1778	13.6%	607	86.7%	0.1274	7.85	7.85	11.3%
7	5%	2035	13905	0.99	215	204	1982	15.1%	618	88.3%	0.1181	8.47	8.47	10.6%
8	5%	2040	15945	1.13	155	147	2129	16.2%	626	89.4%	0.0822	12.16	12.16	7.6%
9	4%	1930	17875	1.27	140	134	2263	17.2%	632	90.3%	0.0782	12.79	12.79	7.3%
10	3%	2135	20010	1.42	130	126	2389	18.2%	636	90.9%	0.0648	15.42	15.42	6.1%
11	2%	2015	22025	1.57	115	113	2502	19.1%	638	91.1%	0.0605	16.52	16.52	5.7%
12	1%	2030	24055	1.71	145	144	2646	20.2%	639	91.3%	0.0769	13.00	13.00	7.1%
13	1%	2000	26055	1.85	120	119	2765	21.1%	640	91.4%	0.0638	15.67	15.67	6.0%
14	0%	2070	28125	2.00	110	110	2875	21.9%	640	91.4%	0.0561	17.82	17.82	5.3%
15	0%	1890	30015	2.13	95	95	2970	22.6%	640	91.4%	0.0529	18.89	18.89	5.0%
16	0%	2225	32240	2.29	50	50	3020	23.0%	640	91.4%	0.0230	43.50	43.50	2.2%
17	0%	2055	34295	2.44	70	70	3090	23.6%	640	91.4%	0.0353	28.36	28.36	3.4%
18	0%	2185	36480	2.59	80	80	3170	24.2%	640	91.4%	0.0380	26.31	26.31	3.7%

**Figure 5.35 :Run 66 Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected**

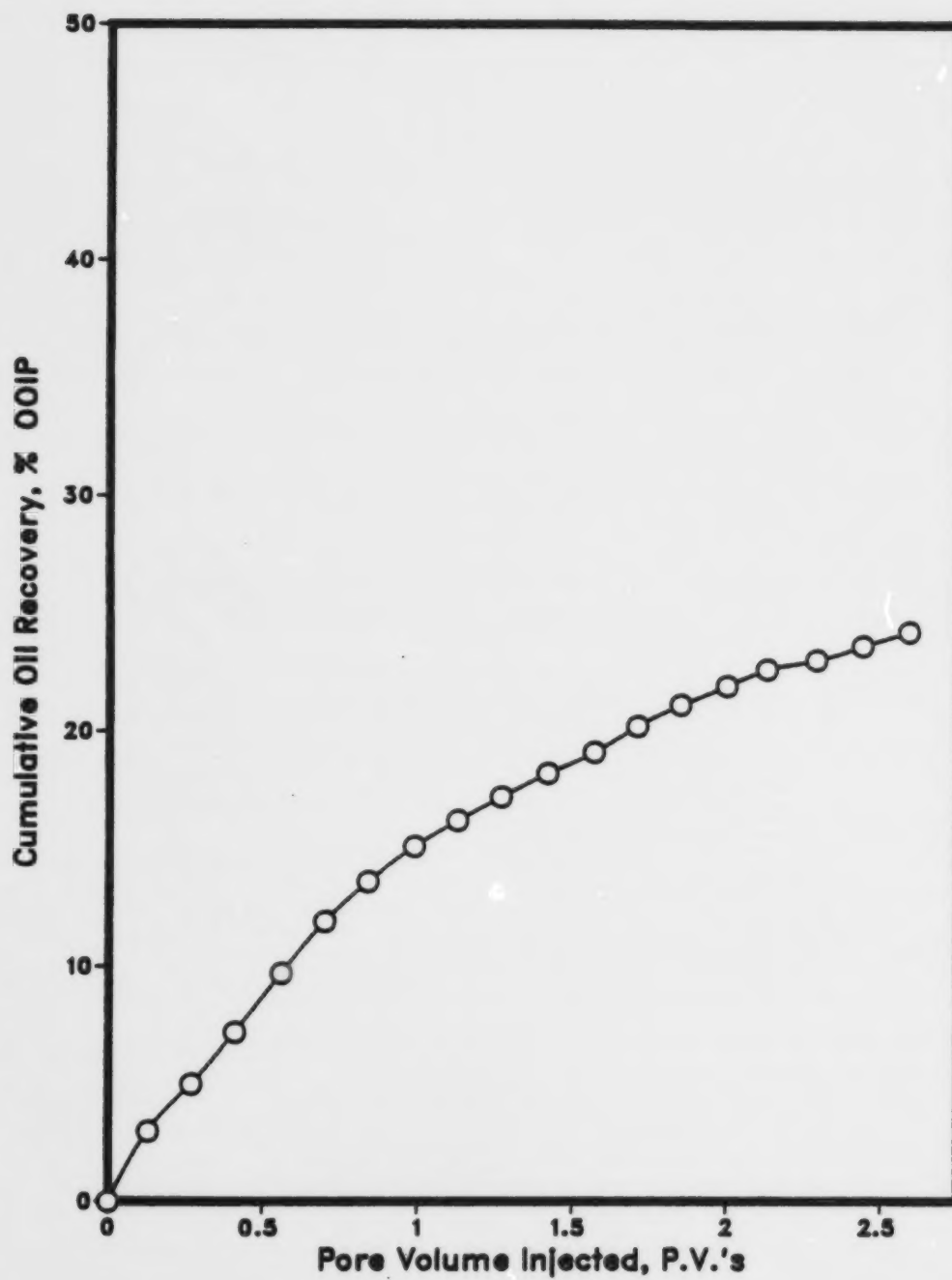


**Figure 5.36 :Run 66 Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

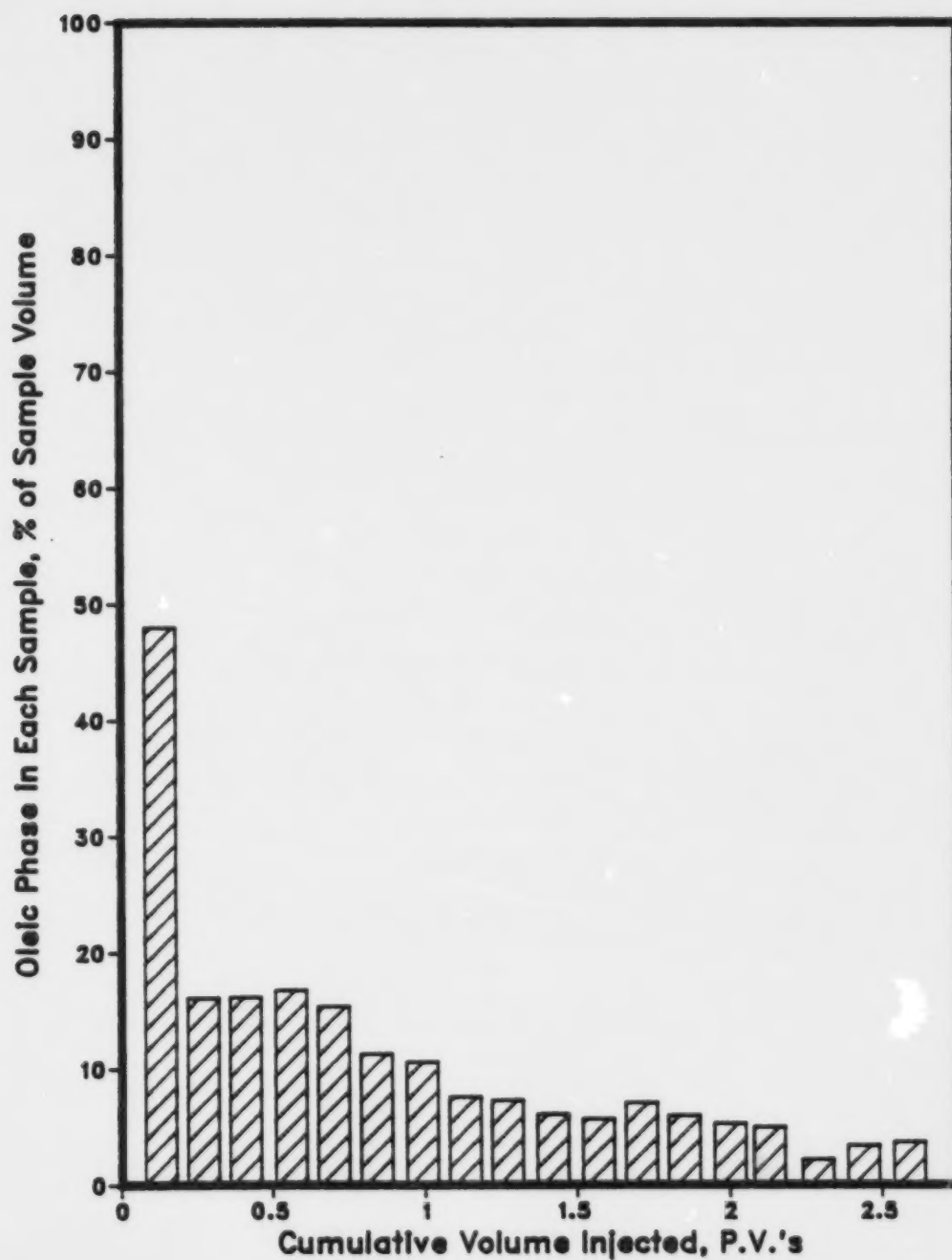


Figure 5.37 :Run 66 Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected

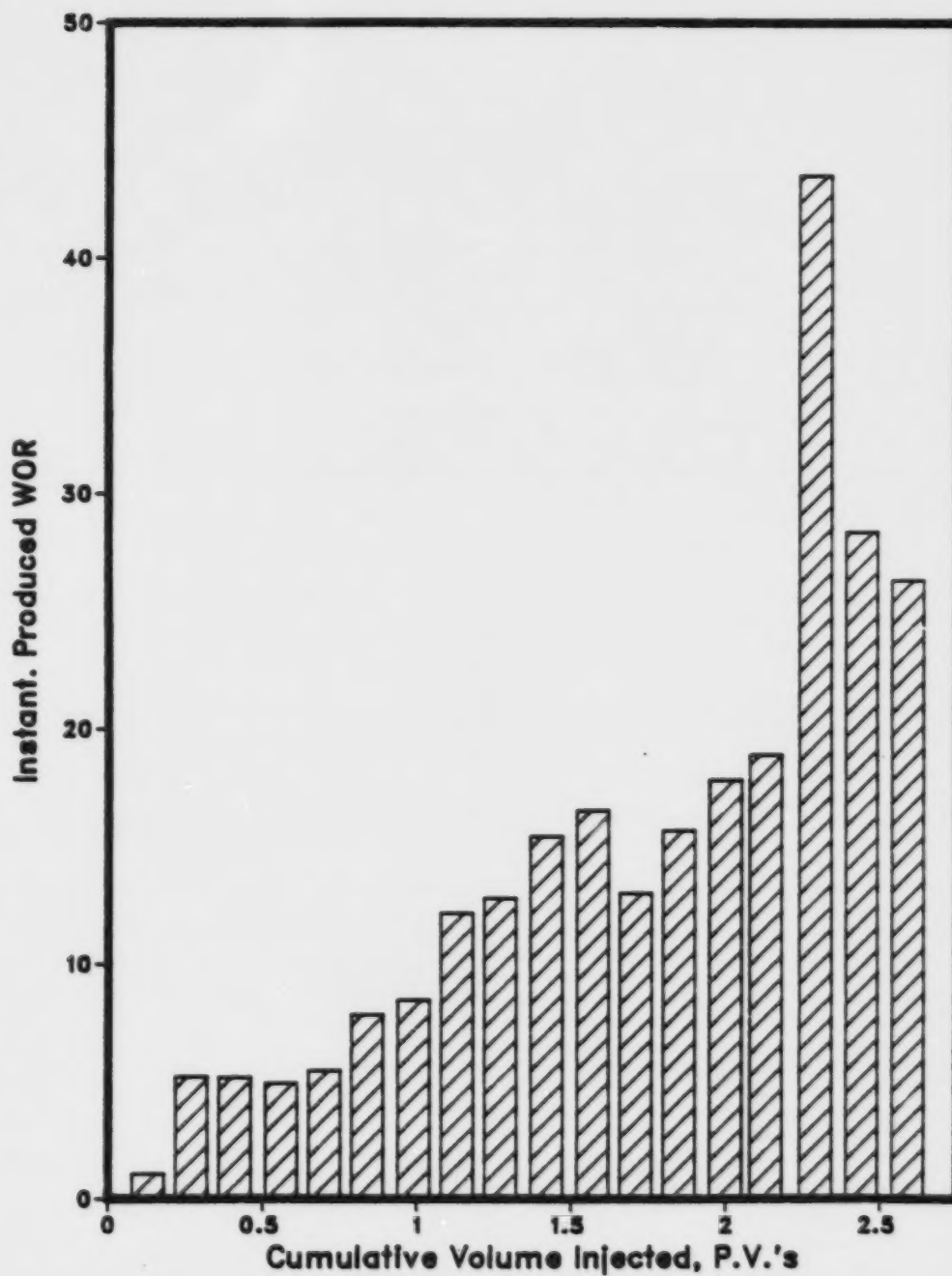


Figure 5.38 :Run 66 Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced

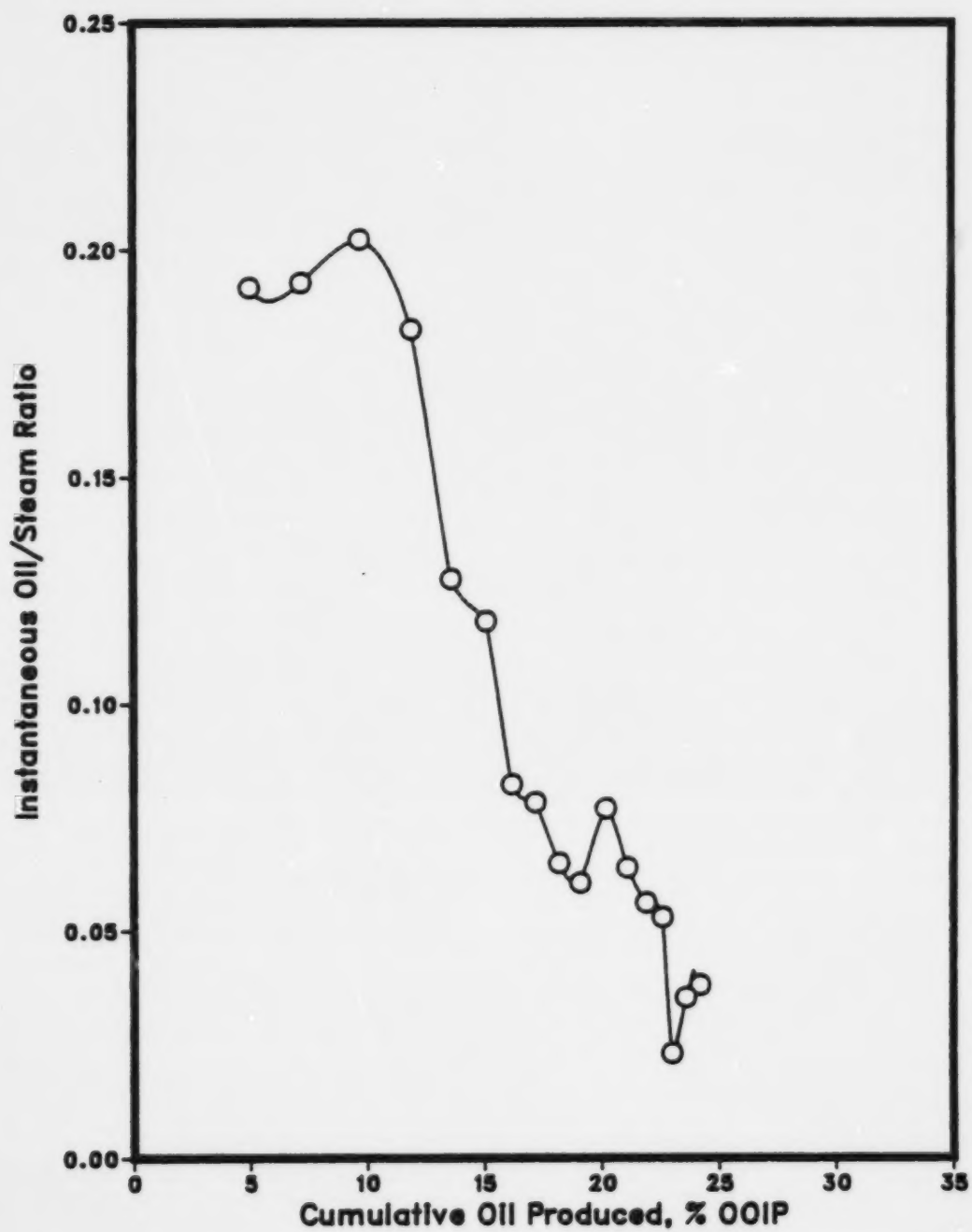


Table 5.1.1 : Run 67 Solvent-Steamflood With Homogeneous Model

HC Pore Volume : 13030.0 cc		Type of Oil Used : Faxam-100										
Pore Volume : 14080.0 cc		Initial Model Temperature : 3.00 C										
Bulk Volume : 42005.0 cc		Water Feed Flow Rate : 213.60 cc/min										
Porosity : 33.5%		Boiler Feed Flow Rate : 29.20 cc/min										
Initial Oil Satn. : 92.5%		Total Flow Rate of Steam : 242.80 cc/min										
Initial H2O Satn. : 7.5%		Solvent Flow Rate : 200.00 cc/min										
Solvent Vol. Inj.: 2100.0 cc (15.0% PV)		Steam Vol. Injected : 32160 cc (2.28 PV)										
Net Oil Recovery : 25.9%		Solvent Recovery : 97.0%										
		Final Oil Saturation : 68.6%										
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)	Cum. Sol. Rec. (%)	Oil:Steam Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample	
1	71%	980	980	0.07	980	284	2.2%	696	33.1%	0.0000	0.00	100.0%
2	88%	1225	2205	0.16	1115	134	3.2%	1677	79.9%	0.0000	0.10	91.0%
3	56%	1590	3795	0.27	410	598	4.6%	1907	90.8%	0.3475	2.88	25.8%
4	16%	1920	5715	0.41	265	821	6.3%	1949	92.8%	0.1601	6.25	13.8%
5	7%	2030	7745	0.55	375	349	9.0%	1975	94.0%	0.2266	4.41	18.5%
6	6%	1935	9680	0.69	405	381	11.9%	1999	95.2%	0.2647	3.78	20.9%
7	5%	2040	11720	0.83	385	366	14.7%	2018	96.1%	0.2326	4.30	18.9%
8	3%	1980	13700	0.97	330	320	17.2%	2028	96.6%	0.2000	5.00	16.7%
9	2%	2030	15730	1.12	230	225	18.9%	2033	96.8%	0.1278	7.83	11.3%
10	1%	2030	17760	1.26	195	193	20.4%	2035	96.9%	0.1063	9.41	9.6%
11	1%	2025	19785	1.41	135	134	21.4%	2036	97.0%	0.0714	14.00	6.7%
12	0%	1985	21770	1.55	130	130	22.4%	2036	97.0%	0.0701	14.27	6.5%
13	0%	2165	23935	1.70	80	80	23.0%	2036	97.0%	0.0384	26.06	3.7%
14	0%	2055	25990	1.85	75	75	23.6%	2036	97.0%	0.0379	26.40	3.6%
15	0%	2115	28105	2.00	85	85	24.2%	2036	97.0%	0.0419	23.88	4.0%
16	0%	2000	30105	2.14	90	90	24.9%	2036	97.0%	0.0471	21.22	4.5%
17	0%	2135	32240	2.29	50	50	25.3%	2036	97.0%	0.0240	41.70	2.3%
18	0%	2020	34260	2.43	70	70	25.9%	2036	97.0%	0.0359	27.86	3.5%

Figure 5.39: Run 67 Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

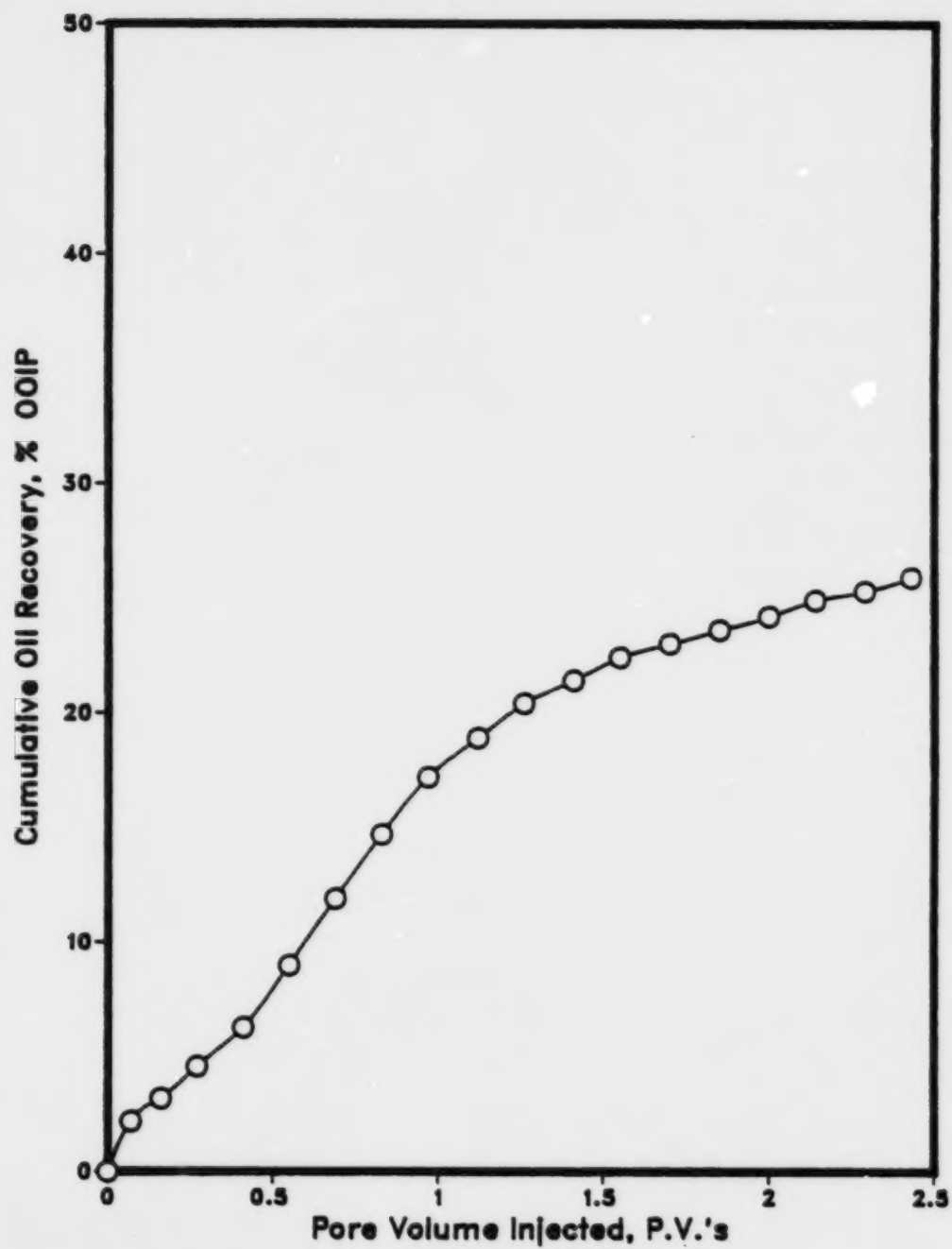


**Figure 5.40 :Run 67 Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

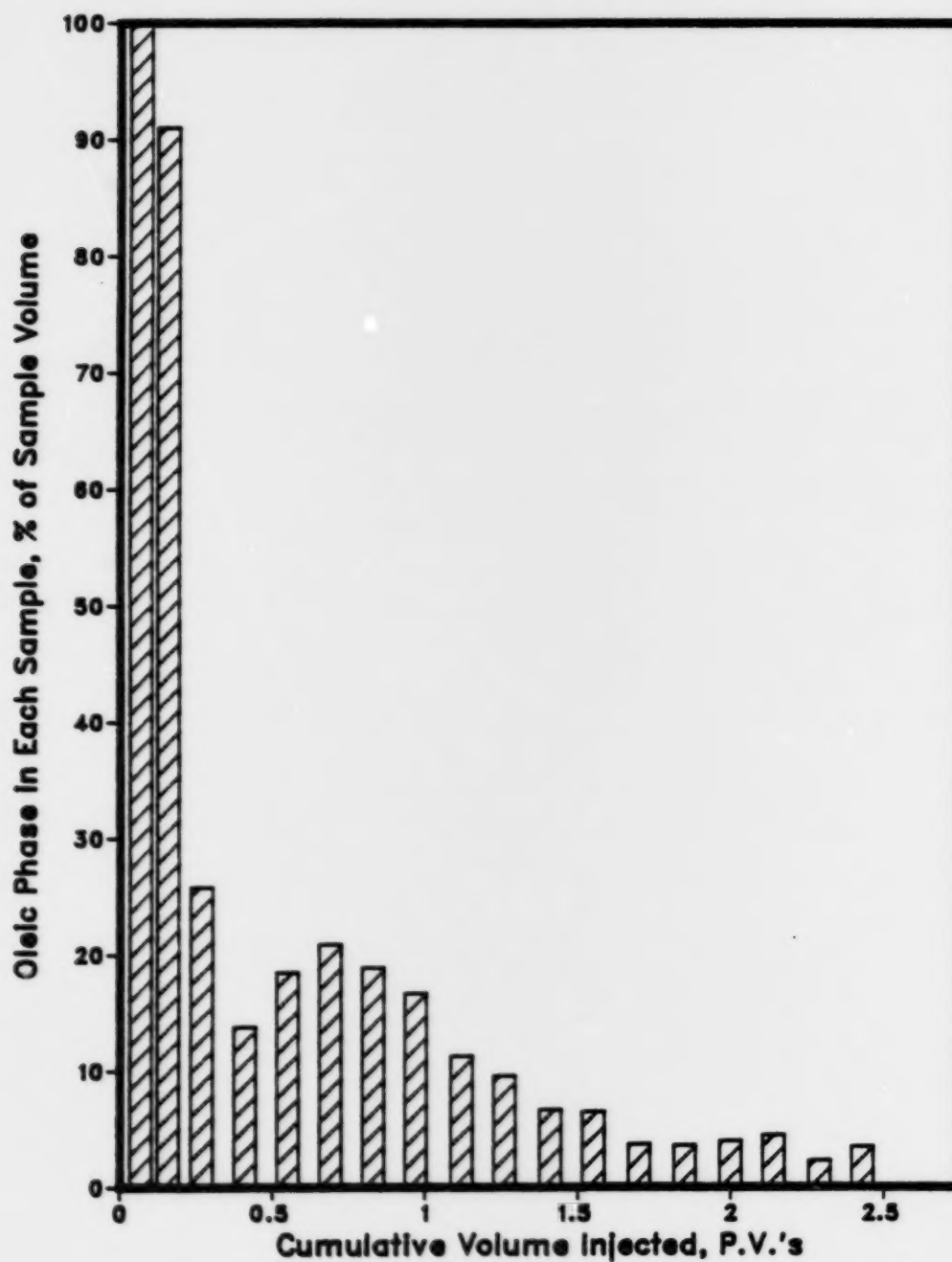


**Figure 5.41 :Run 67 Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

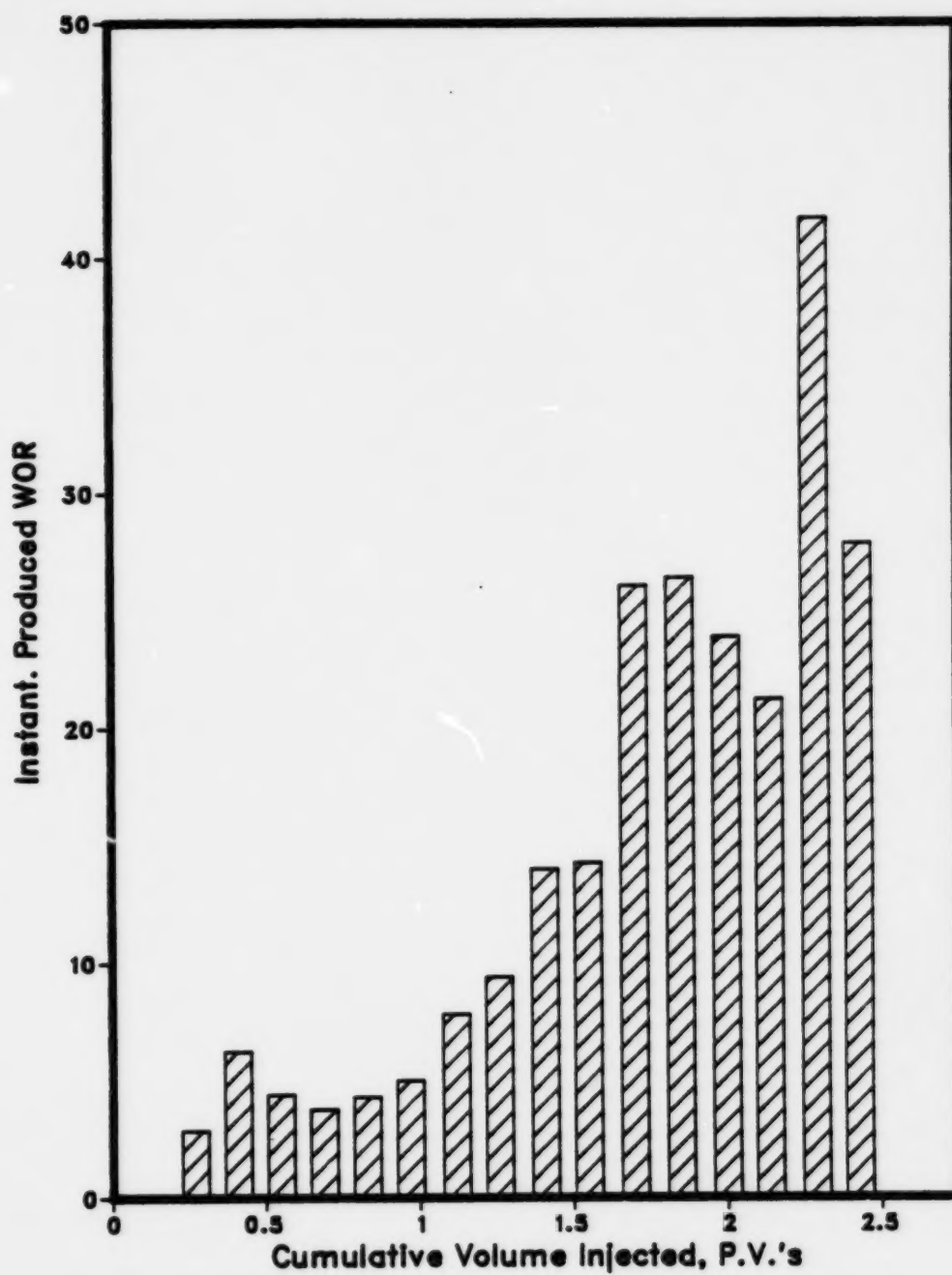
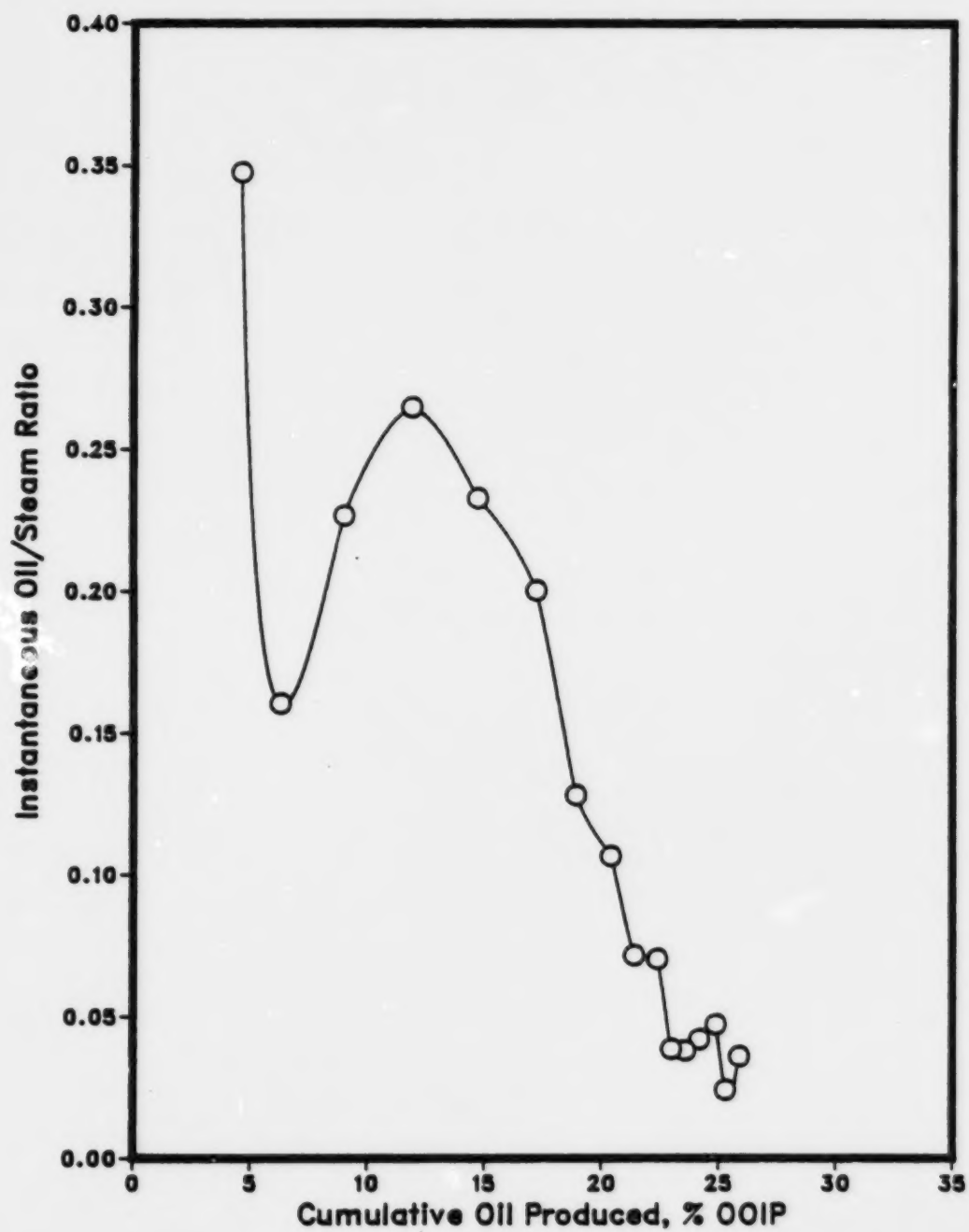


Figure 5.42 :Run 67 Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced



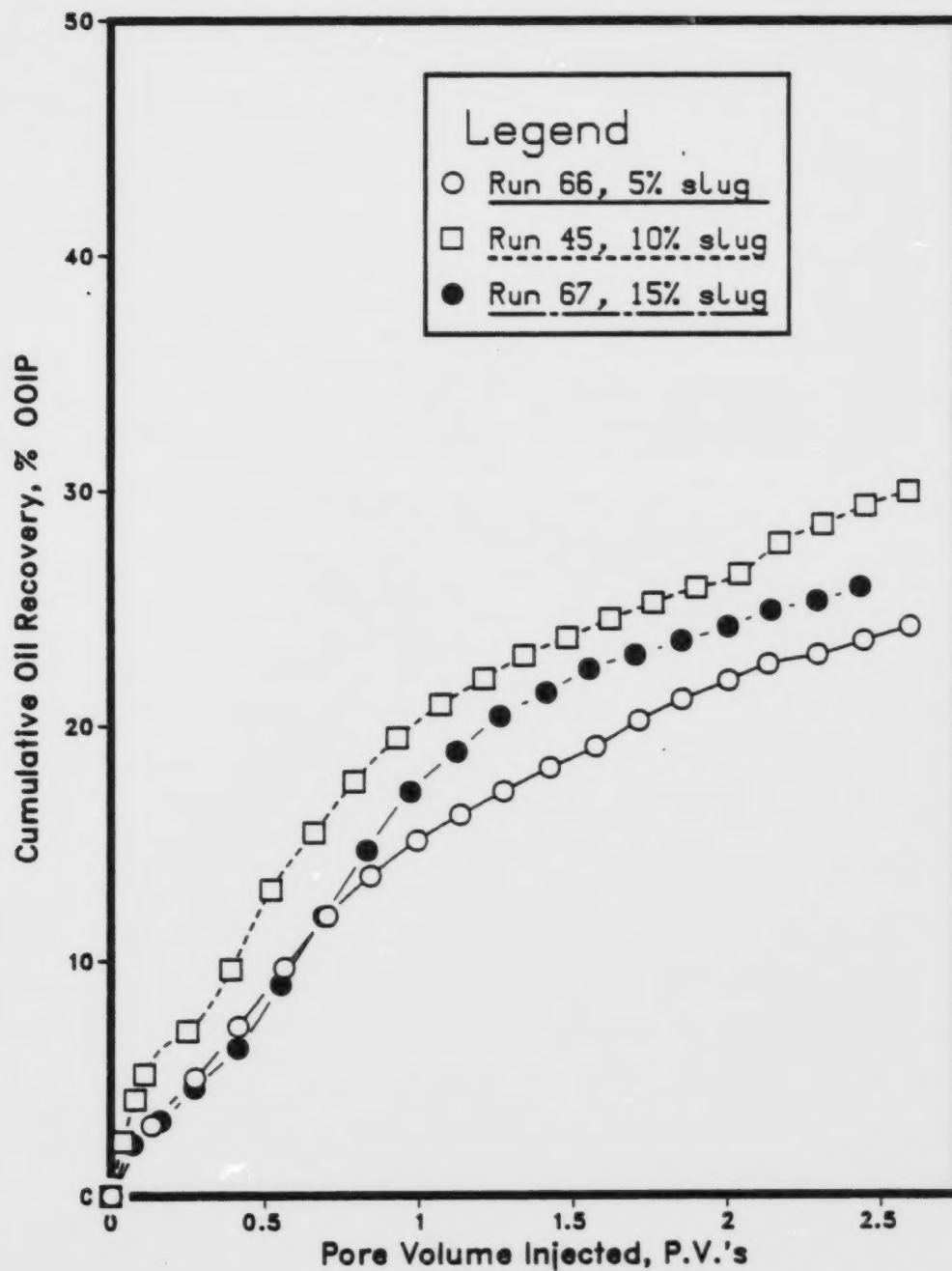
comparison plot (Figure 5.43) of the recovery curves for the three experiments indicates that Run 45 had the best recovery with Run 67 second and Run 66 having the least attractive recovery. From the results of the three experiments it appeared that the 10% solvent slug run allowed a more stable displacement to occur in the model and thus a greater recovery. Run 45 (10% slug) achieved the optimal balance between oil viscosity reduction and channelling which means that some of the oil does not contact the solvent. In the case of the 5% solvent slug experiment, less solvent channelling existed in the oil, thus less extensive steam penetration of the oil occurred and consequently less oil was mobilized. Steam advance in Run 66 (5% slug) is quite unusual, and departs strongly from a radial type advance. It seems that the solvent was displaced along the right edge of the model and from there on, steam advanced as a front from right to left (see Figure A.102 for the terminal time). For the 15% solvent slug run the larger solvent slug used created larger solvent channels in the model which allowed the steam to flow more directly from the injection to production wells and therefore more of the steam was partially diverted away from heating the oil than during Run 45. It was concluded from the results of Runs 66, 67 and 45 that there exists an optimal slug size of approximately 10% of the model pore volume which maximizes the oil recovered by a solvent-steamflood process.

Effect of Bottom Water Thickness on Steamflood Response

Studies ^{63,65} similar to the present research investigated the effect of bottom water thickness on the steamflood response in the Aberfeldy heavy oil reservoir. In each of the studies carried out by Kasraie and Farouq Ali (numerical) ⁶⁵ and Proctor, George and Farouq Ali (experimental)⁶³, it was observed that when bottom water was present during a steamflood, much less steam flowed in the oil region than that in the absence of water.

Kasraie and Farouq Ali ⁶⁵ performed mathematical simulations of steamfloods in the Aberfeldy formation to investigate the effect of bottom water thickness on the overall oil recovery yielded by a steamflood. In these simulations, steam was injected into the oil

Figure 5.43 :Comparison of the Effect of Solvent Slug Size on Solvent-Steamflood Recoveries for Runs 45, 66 & 67



zone only, and the producers were completed in the oil zone. The results quite clearly indicated that oil recovery declined steeply as the bottom water thickness increased. It was also reported that the oil-steam ratio reached a low earlier for the thicker bottom water zones than it did for the thinner water regions. This implied that in thicker water zones, the steam penetrated the bottom water earlier, and from then on, there was little improvement in the oil displacement efficiency. It was therefore concluded that when bottom water exists, much less steam travels in the oil zone than when bottom water is absent and thus even though oil is mobilized, considerable amounts of water continue to advance from the water zone into the producers.

The scaled model study carried out by Proctor, George and Farouq Ali ⁶³ involved experiments in which the bottom water model of the Aberfeldy was steamflooded. Runs 32, 33 and 39 involved steamflooding a model of the Aberfeldy formation with varying bottom water thicknesses of 2.3%, 4.0% and 12.5% of the total model thickness, respectively. The oil recoveries obtained from Runs 32, 33 and 39 were 22.8%, 22.9% and 16.8% OOIP, respectively. Recoveries for the three runs indicate that as the bottom water layer thickness increased, oil recovery correspondingly decreased. The substantially greater oil recovery of 31.8% OOIP for Run 26, which was a conventional steamflood of the homogeneous model of the Aberfeldy, pointed out the deleterious effects that the bottom water had on the displacement efficiencies and recoveries of Runs 32, 33 and 39. Temperature profiles of the experiments suggested that the injected heat moved rapidly in the bottom water layer and heat advance in the upper part of the model was virtually stationary. This indicated that a hot waterflood existed once the steam condensed and the condensate quickly migrated into the less flow resistant bottom water. It was concluded from this study that the bottom water had very detrimental effects on the thermal efficiency of the steamflood and as the bottom water thickness increased the heat loss of the steam to the bottom water was intensified.

The results of these two studies ^{63,65} agreed in that as the bottom water thickness increased, the thermal efficiency, sweep efficiency and net oil recovery of the steamflood dropped. These findings support the possibility of employing a small solvent slug prior to a steamflood process in order to partially divert the steam away from the underlying water and into the above oil zone, so to delay the movement of steam downward into the bottom water. The use of solvent in combination with a steamflood process will be discussed in the following section.

Effect of Bottom Water Thickness on Solvent-Steamflood Response

The purpose of the initial solvent injection into the oil layer prior to steamflooding was to create a pathway in the oil layer for the steam to follow in an attempt to improve the oil recovery compared to conventionally steamflooding a bottom water formation.

An assumption of this study was that during initial solvent injection into the oil zone of the model, channelling or viscous fingering of the injected solvent into the oil region was predominant. This assumption was confirmed by the results of the solvent flood (Run 40) which was previously discussed. The extensive viscous fingering of the solvent into the oil was caused by the large contrast in mobilities between the solvent (k_{rd}/μ_d) and the oil (k_{ro}/μ_o) as well as a high solvent injection rate. The huge contrast in mobilities was mainly due to the large difference in viscosities of the solvent (μ_d) and the model oil (μ_o) at the initial model temperature of approximately 3.0°C. The solvent had a much smaller viscosity (about 10 cp) than the heavy oil (approximately 1300 cp) at the initial temperature conditions. As well, the solvent permeability (k_{rd}) is higher than the heavy oil permeability (k_{ro}) initially during the solvent injection, the corresponding value for mobility ratio in this case, as defined by the equation below and discussed by Collins ⁶⁶, would be even larger.

$$\text{Mobility Ratio} = M = \frac{\text{mobility of displacing fluid}}{\text{mobility of displaced fluid}} = \frac{k_{rd}/\mu_d}{k_{ro}/\mu_o}$$

The higher the value of mobility ratio and the solvent injection rate, the less stable the displacement would be, therefore for this situation the large mobility ratio would be unfavourable due to the large discrepancy between the solvent and oil viscosities. The displacement of the heavy oil by the solvent would be considered highly unstable due to the unfavourable mobility ratio governing the displacement and the relatively high solvent injection rate. Therefore the desired mixing of the solvent with the oil region of the model would be highly probable and thus solvent channelling was assumed to occur during the initial stages of the solvent-steamflood experiments.

Runs 49, 50, 51, 53 and 54 all involved injecting 0.10 pore volume of solvent (Heavy Virgin Naphtha) followed by a continuous steamflood of a model containing a bottom water layer. The only difference between the five bottom water experiments was that the bottom water thickness varied for each run. Bottom water thickness was altered in each run so to investigate its effect on the oil recovery.

The tabulated results for Runs 49, 50, 51, 53 and 54 are presented in Tables 5.12, 5.13, 5.14, 5.15 and 5.16, respectively. The bottom water thicknesses for Runs 49 (8.8% of gross model thickness), 50 (10.2% of gross model thickness) and 54 (12.2% of gross model thickness) were about the same, whereas Runs 51 (26.2% of gross model thickness) and 53 (15.2% of gross model thickness) had much thicker bottom water layers. The injection well for the model was situated so to inject fluids into the upper portion of the model. This was to ensure that the solvent and steam would not flow directly into the bottom water layer and override the oil immediately upon injection.

Comparison of the recovery curves for Runs 49 (Figure 5.44), 50 (Figure 5.48), 51 (Figure 5.52), 53 (Figure 5.56) and 54 (Figure 5.60) demonstrate the deleterious effect bottom water thickness had on oil recovery. The recovery curves for Runs 49, 51 and 54 were much the same due to similarities in bottom water thicknesses, whereas the curves for Run 51 and 53 differed from Figures 5.44, 5.48 and 5.60 due to thicker bottom water

layers. During the initial stages of the Runs 49, 50 and 54 the recovery curves moderately increased up to about 0.50 pore volumes at which point the slope of the curves became constant forming a relatively straight line for the remainder of the experiment. Due to the presence of bottom water the initial increase in the recovery curves for these three experiments was not as marked as in the previous solvent-steamflood base runs (Runs 44, 45 & 46). The moderate rise of oil recovery in Figures 5.44, 5.48 and 5.60 during the primary run stages represents the injected solvent forming flow paths into the oil layer. This helped prevent the steam from being entirely lost to the bottom water layer and thus assisted in mobilizing more of the in-place oil. However the existence of bottom water eventually hindered the stability of the steam displacement in the model and reduced the heating efficiency of the steam in the oil region. This yielded a smaller oil recovery compared to previous homogeneous solvent-steamfloods (Runs 44, 45 & 46). The straight line segment of the three curves (Figures 5.44, 5.48 & 5.60) symbolizes the steam continuing to sweep through the oil section recovering additional oil while being partially lost to the bottom water. Runs 51 and 53 had much thicker bottom water layers than Runs 49, 50 and 54 which hampered solvent and steam injection into the oil zone. The consequence was a substantial reduction in the overall oil recovery. Figures 5.52 (Run 51) and 5.56 (Run 53) are in contrast with the recovery curves for Runs 49, 50 and 54 in that the plots are basically straight lines with much lower recoveries than Figures 5.44, 5.48 and 5.60. The straight line in Figures 5.52 and 5.56 represented the continuous injection of steam which mobilized oil in the upper portion of the model while throughout the run a majority of the steam's heat was scavenged by the underlying bottom water. Therefore the steam displacements in Runs 51 and 53 were considerably less stable than the displacements in Run 49, 50 and 54 due to the thicker bottom water zones of Runs 51 and 53.

The bar graphs of volume as a percentage of oleic phase in each sample taken versus cumulative volume injected and instantaneous produced WOR versus cumulative

volume injected for Runs 49 (Fig. 5.45 & 5.46), 50 (Fig. 5.49 & 5.50), 51 (Fig. 5.53 & 5.54), 53 (Fig. 5.57 & 5.58) and 54 (Fig. 5.61 & 5.62) indicate that the bottom water was a dominating factor in the experiments. Figures 5.45, 5.49, 5.53, 5.57 and 5.61 suggested that during the initial stages of the five runs the injected steam penetrated into the oil layer and formed an oil bank ahead of the steam zone. Soon after the formation of the oil bank, steam breakthrough occurred. For Runs 49, 50, and 54 steam breakthrough existed at about 0.50 pore volumes injected and at about 0.25 pore volumes injected for Runs 51 and 53. The values of instantaneous hydrocarbon produced in the sample for Run 51 and 53 were considerably lower than those for Runs 49, 50 and 54, due to the thicker bottom water zones of Runs 51 and 53. Figures 5.46, 5.50, 5.54, 5.58 and 5.62 also indicated that a distinct steam breakthrough occurred during all of the five bottom water runs. Again steam breakthrough appeared to occur sooner and was less distinct for Runs 51 and 53 due to the thicker bottom water zones.

The plots of instantaneous oil/steam ratio versus cumulative oil produced are displayed in Figures 5.47 (Run 49), 5.51 (Run 50), 5.55 (Run 51), 5.59 (Run 53) and 5.63 (Run 54). A distinct breakthrough was again observed in these figures which was distinguished by the steep decline in the instantaneous oil/steam ratio values between the first few points of each plot. In the case of Runs 51 and 53 the reduced oil/steam ratio settles down to a value of approximately 0.5, showing that the oil layer above continues to be heated by steam.

Top view temperature contour plots for Run 49 (Fig. A.119-A.126), 50 (Fig. A.131-A.138), 51 (Fig. A.143-A.150), 53 (Fig. A.155-A.162) and 54 (Fig. A.167-A.174) exhibits the temperature profiles for each of the experiments at every 0.25 pore volumes injected into the model. For Runs 49, 50 and 54, the temperature profiles revealed that early in the experiments the solvent created a flow path into the oil zone enabling the steam to flow more readily through the oil layer and as the steamflood progressed the steam eventually began to override the oil by travelling through the bottom

Table 5.1.2: Run 49 Solvent-Steamflood With Bottom Water

HC Pore Volume:	13460.0 cc	Type of Oil Used:	Faxam-100
Pore Volume:	15530.0 cc	Initial Model Temperature:	3.00 C
Bulk Volume:	42005.0 cc	Water Feed Flow Rate:	200.00 cc/min
Porosity:	37.0%	Boiler Feed Flow Rate:	29.20 cc/min
Initial Oil Satn.:	86.7%	Total Flow Rate of Steam:	229.20 cc/min
Initial H ₂ O Satn.:	13.3%	Solvent Flow Rate:	200.00 cc/min
Solvent Vol. Inj.:	1400.0 cc (10.0% PV)	Bottom Water Layer Thickness:	8.8 % (% Gross Thickness)
Steam Vol. Inj.:	31630.0 cc (2.04 PV)		

Net Oil Recovery : 23.3%					Solvent Recovery : 84.6%					Final Oil Saturation : 66.5%				
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)		HC Prod. (cc)	Oil Prod. (cc)		Cum. Oil Rec. (%OOIP)		Cum. Sol. Rec. (cc)	Inst. Prod. WOR	Oil-Steam Ratio	Inst. HC Prod. % of Sample	
			(cc)	(P.V.)		(cc)	(cc)	(%)	(%)					
1	7%	405	1340	0.09	185	172	172	1.3%	13	0.9%	1.19	0.0000	45.7%	
2	60%	905	2245	0.14	740	296	468	3.5%	457	32.6%	0.22	0.0000	81.8%	
3	72%	840	3085	0.20	740	207	675	5.0%	990	70.7%	0.14	0.0000	88.1%	
4	32%	1980	5065	0.33	490	333	1008	7.5%	1147	81.9%	3.04	0.3289	24.7%	
5	8%	2085	7150	0.46	205	189	1197	8.9%	1163	83.1%	9.17	0.1090	9.8%	
6	5%	1980	9130	0.59	190	181	1378	10.2%	1172	83.7%	9.42	0.1061	9.6%	
7	3%	2065	11195	0.72	195	189	1567	11.6%	1178	84.1%	9.59	0.1043	9.4%	
8	2%	2005	13200	0.85	170	167	1734	12.9%	1181	84.4%	10.79	0.0926	8.5%	
9	2%	2065	15265	0.98	150	147	1881	14.0%	1184	84.6%	12.77	0.0783	7.3%	
10	0%	2000	17265	1.11	140	140	2021	15.0%	1184	84.6%	13.29	0.0753	7.0%	
11	0%	2000	19265	1.24	125	125	2146	15.9%	1184	84.6%	15.00	0.0667	6.3%	
12	0%	1935	21200	1.37	120	120	2266	16.8%	1184	84.6%	15.13	0.0661	6.2%	
13	0%	2035	23235	1.50	120	120	2386	17.7%	1184	84.6%	15.96	0.0627	5.9%	
14	0%	1970	25205	1.62	110	110	2496	18.5%	1184	84.6%	16.91	0.0591	5.6%	
15	0%	1945	27150	1.75	230	230	2726	20.3%	1184	84.6%	7.46	0.1341	11.8%	
16	0%	1915	29065	1.87	165	165	2891	21.5%	1184	84.6%	10.61	0.0943	8.6%	
17	0%	2040	31105	2.00	75	75	2966	22.0%	1184	84.6%	26.20	0.0382	3.7%	
18	0%	1925	33030	2.13	165	165	3131	23.3%	1184	84.6%	10.67	0.0938	8.6%	

Figure 5.44 :Run 49 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected

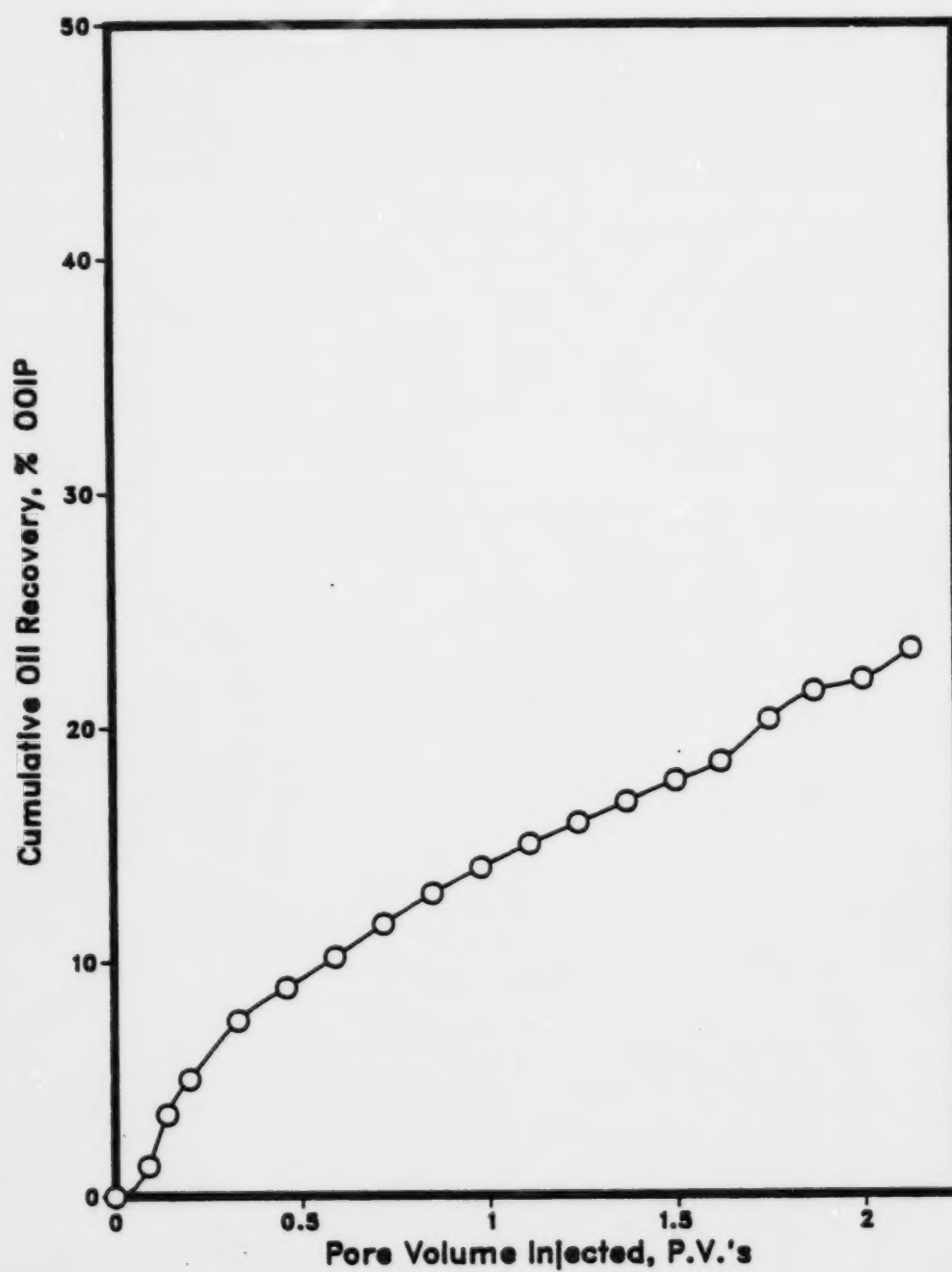


**Figure 5.45 :Run 49 Solvent-Steamflood With Bottom Water
Oleic Phase in Each Sample Vs. Cumulative Volume Injected**

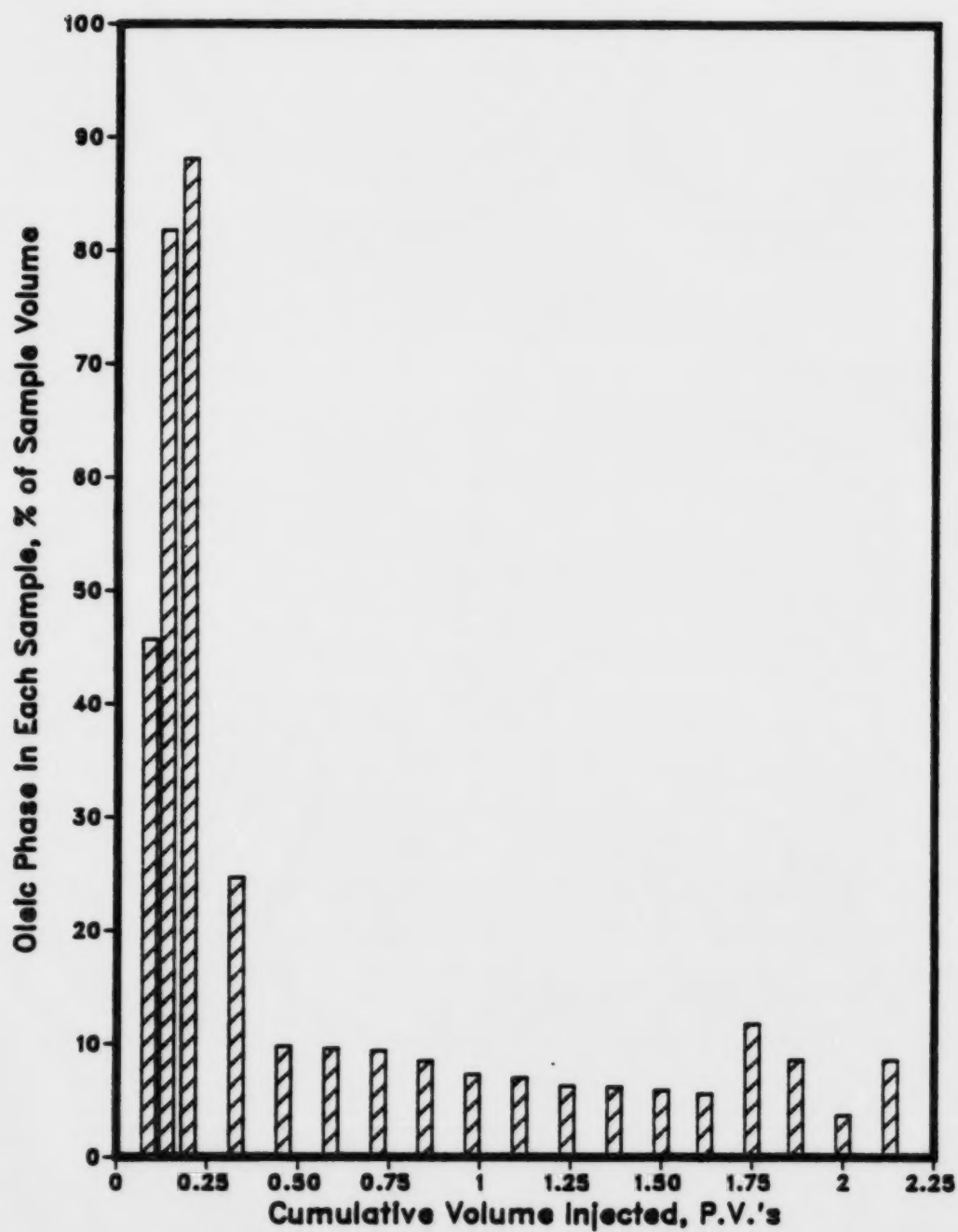


**Figure 5.46 :Run 49 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

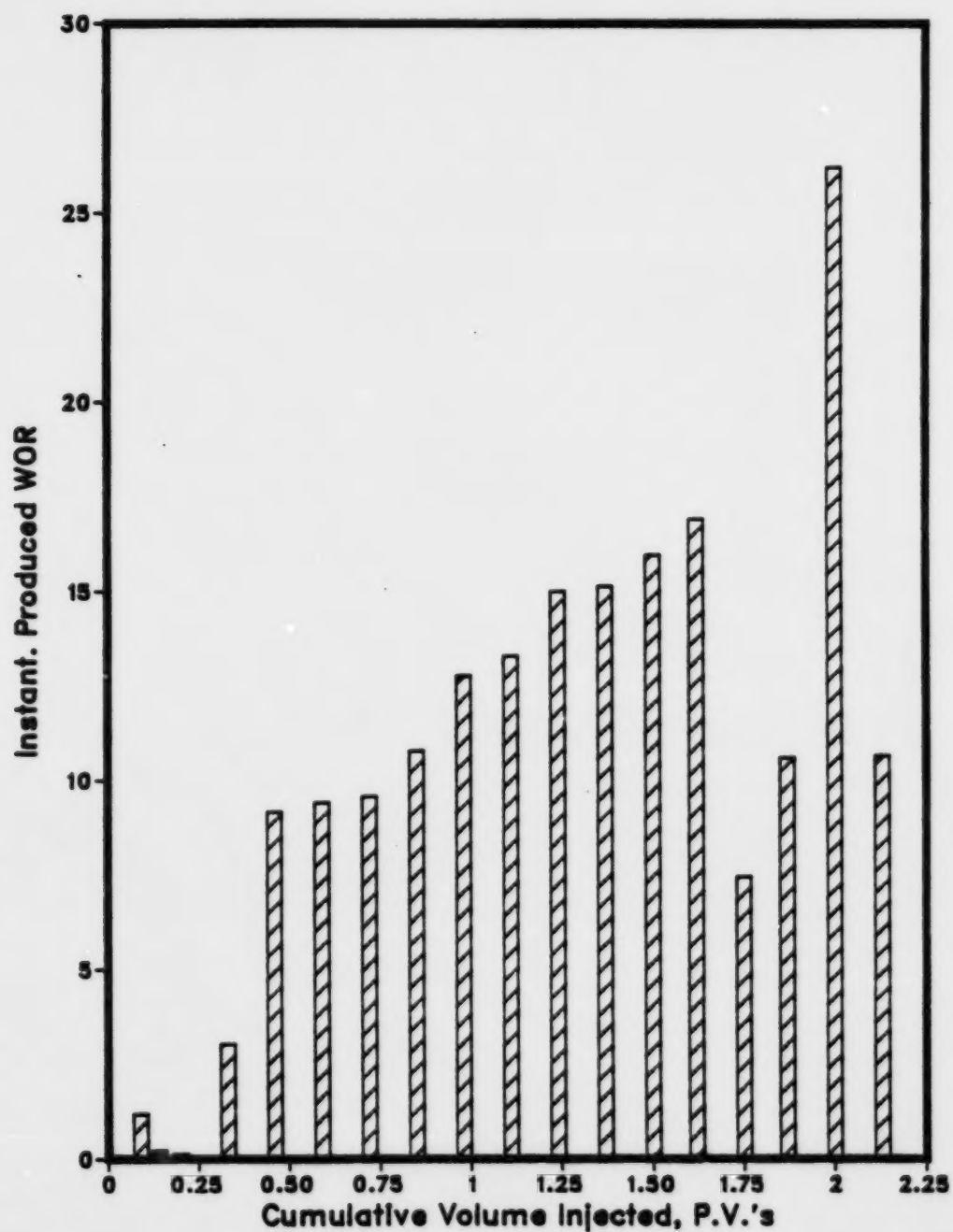


Figure 5.47 :Run 49 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

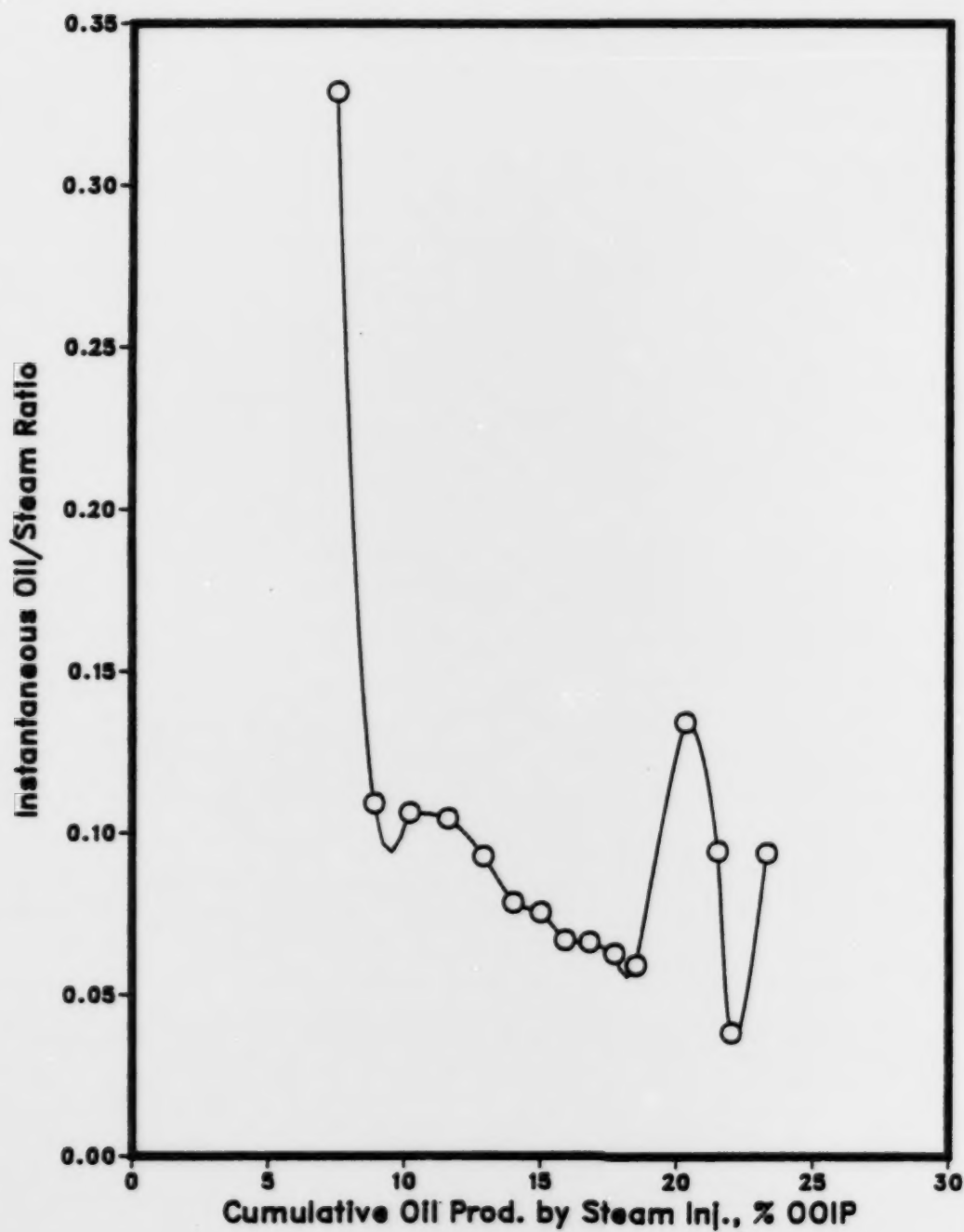


Table 5.13 : Run 50 Solvent-Steamflood With Bottom Water

HC Pore Volume :	13720.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15037.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	35.8%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	91.2%	Total Flow Rate of Steam :	229.20 cc/min
Initial H ₂ O Satn. :	8.8%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	1400.0 cc (10.0% PV)	Bottom Water Thickness :	10.2 % (% Gross Thickness)
Steam Vol. Inj. :	32635.0 cc (2.16 PV)		

Net Oil Recovery : 25.4 % Solvent Recovery : 88.5 % Final Oil Saturation : 68.0 %

Cyl. No.	Solvent Conc. (%)	Tot. Vol.		Cum. Vol. Inj.		HC Prod.		Oil Prod.		Cum. Oil Rec.		Cum. Sol. Rec.		Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
		Inj. (cc)	(cc)	(cc)	(P.V.)	(cc)	(cc)	(cc)	(cc)	(cc)	(%OOIP)	(cc)	(%)			
1	60%	1120	1120	1120	0.07	1120	448	448	3.3%	672	48.0%	0.0000	0.0000	0.00	0.00	100.0%
2	65%	1005	2125	665	0.14	233	681	233	5.0%	1104	78.9%	0.0000	0.0000	0.51	0.51	66.2%
3	28%	1435	3560	235	0.24	169	850	169	6.2%	1170	83.6%	0.1958	0.1958	5.11	5.11	16.4%
4	9%	2080	5640	410	0.38	373	1223	373	8.9%	1207	86.2%	0.2455	0.2455	4.07	4.07	19.7%
5	5%	1940	7580	440	0.50	418	1641	418	12.0%	1229	87.8%	0.2933	0.2933	3.41	3.41	22.7%
6	2%	2060	9640	225	0.64	221	1862	221	13.6%	1233	88.1%	0.1226	0.1226	8.16	8.16	10.9%
7	1%	2040	11680	225	0.78	223	2085	223	15.2%	1235	88.2%	0.1240	0.1240	8.07	8.07	11.0%
8	1%	2095	13775	190	0.92	188	2273	188	16.6%	1237	88.4%	0.0997	0.0997	10.03	10.03	9.1%
9	1%	1980	15755	155	1.05	153	2426	153	17.7%	1239	88.5%	0.0849	0.0849	11.77	11.77	7.8%
10	0%	2035	17790	125	1.18	125	2551	125	18.6%	1239	88.5%	0.0654	0.0654	15.28	15.28	6.1%
11	0%	1975	19765	115	1.31	115	2666	115	19.4%	1239	88.5%	0.0618	0.0618	16.17	16.17	5.8%
12	0%	2140	21905	110	1.46	110	2776	110	20.2%	1239	88.5%	0.0542	0.0542	18.45	18.45	5.1%
13	0%	2020	23925	140	1.59	140	2916	140	21.3%	1239	88.5%	0.0745	0.0745	13.43	13.43	6.9%
14	0%	2035	25960	105	1.73	105	3021	105	22.0%	1239	88.5%	0.0544	0.0544	18.38	18.38	5.2%
15	0%	1960	27920	115	1.86	115	3136	115	22.9%	1239	88.5%	0.0623	0.0623	16.04	16.04	5.9%
16	0%	2065	29985	105	1.99	105	3241	105	23.6%	1239	88.5%	0.0536	0.0536	18.67	18.67	5.1%
17	0%	1940	31925	100	2.12	100	3341	100	24.4%	1239	88.5%	0.0543	0.0543	18.40	18.40	5.2%
18	0%	2110	34035	150	2.26	150	3491	150	25.4%	1239	88.5%	0.0765	0.0765	13.07	13.07	7.1%

Figure 5.48 :Run 50 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected

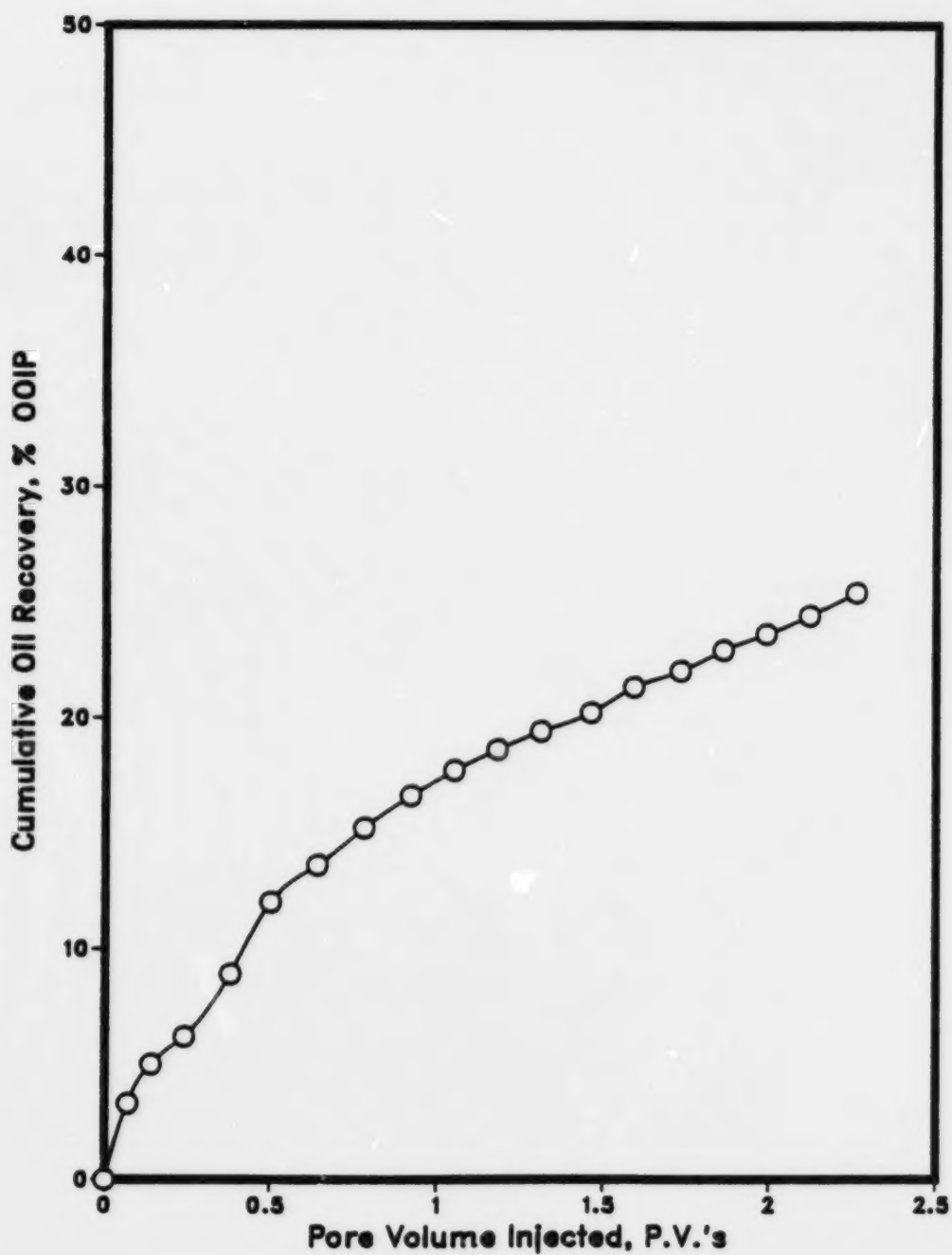


**Figure 5.49 :Run 50 Solventflood—Steamflood With Bottom Water
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

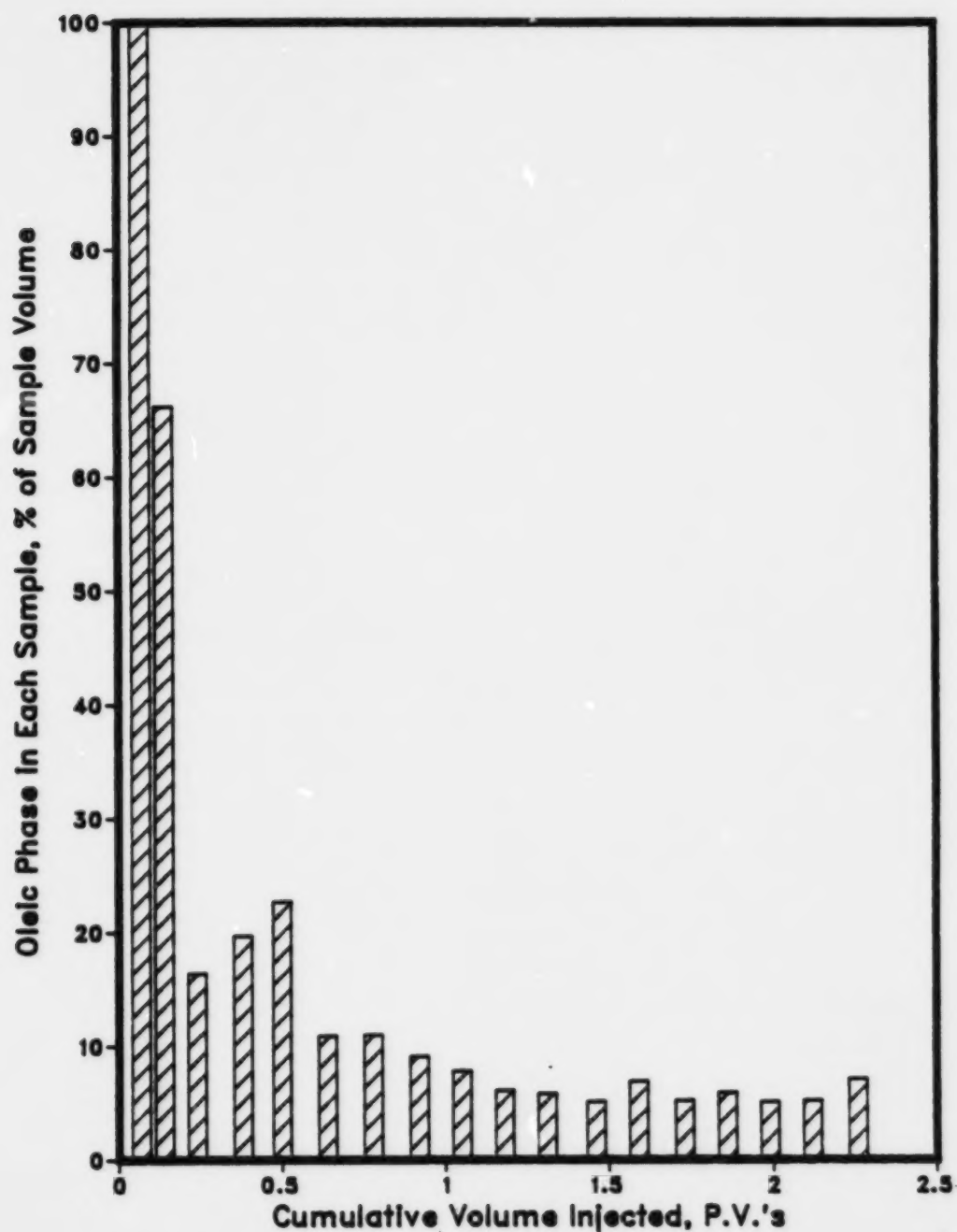


**Figure 5.50 :Run 50 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

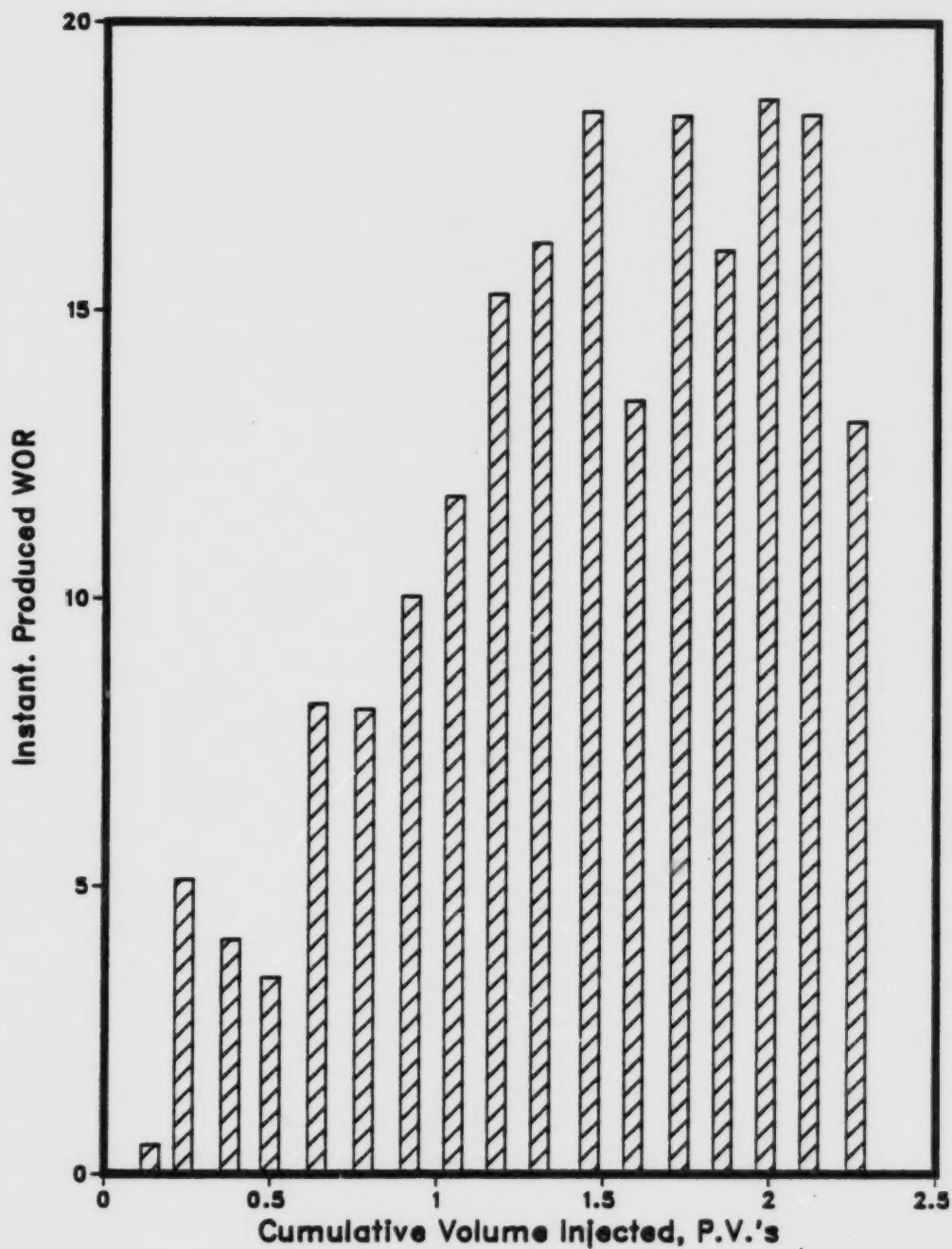


**Figure 5.51 :Run 50 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced**

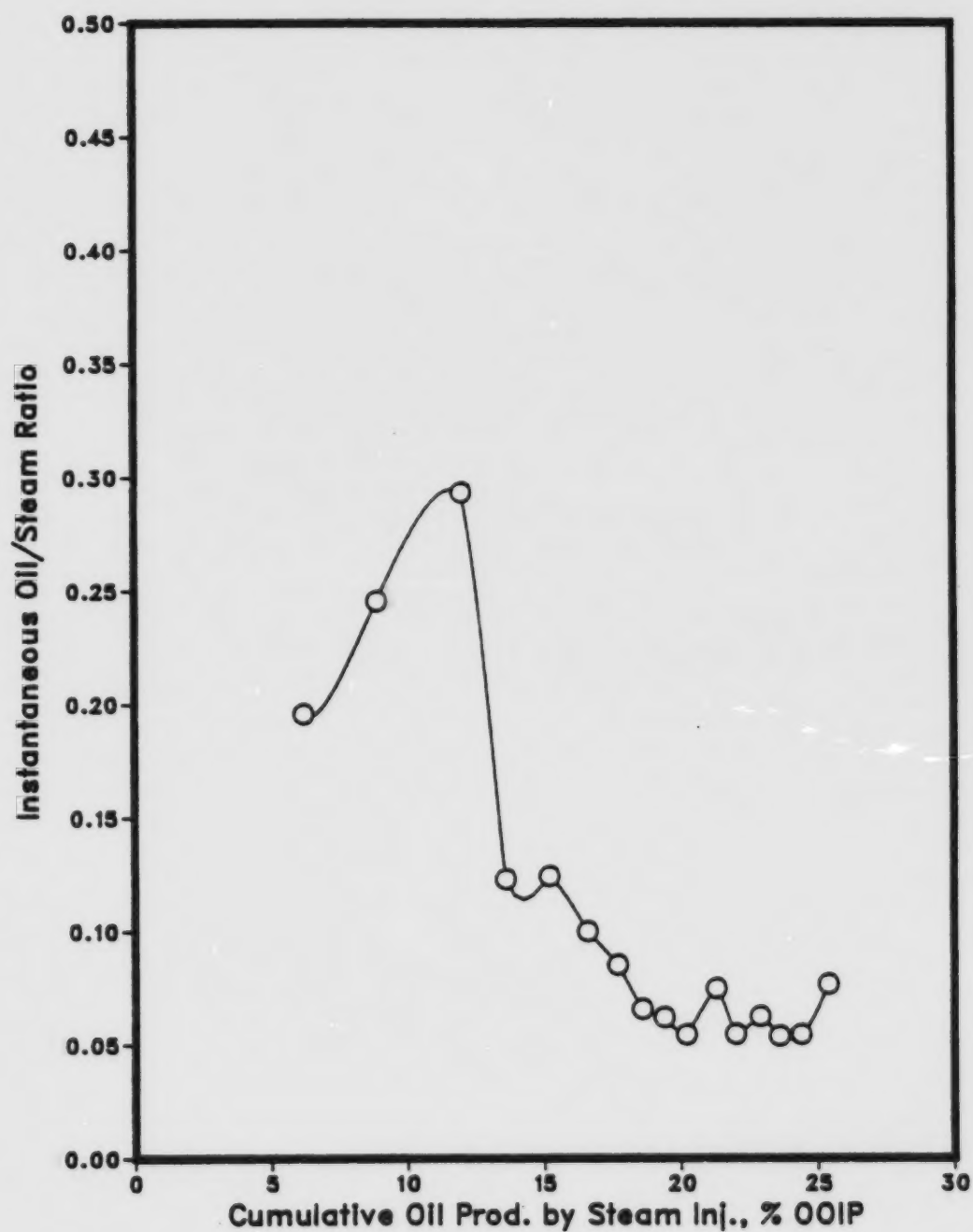


Table 5.14 : Run 51 Solvent-Steamflood With Bottom Water

HC Pore Volume : 10590.0 cc		Type of Oil Used : Faxam-100										
Pore Volume : 15820.0 cc		Initial Model Temperature : 3.00 C										
Bulk Volume : 42005.0 cc		Water Feed Flow Rate : 200.00 cc/min										
Porosity : 37.7%		Boiler Feed Flow Rate : 29.20 cc/min										
Initial Oil Satn. : 66.9%		Total Flow Rate of Steam : 229.20 cc/min										
Initial H2O Satn. : 33.1%		Solvent Flow Rate : 200.00 cc/min										
Solvent Vol. Inj. : 1400.0 cc (10.0% PV)		Bottom Water Thickness : 26.2 % (% Gross Model Thickness)										
Steam Vol. Inj. : 30980.0 cc (1.9% PV)												
Net Oil Recovery : 14.3%		Solvent Recovery : 40.8%										
		Final Oil Saturation : 57.3%										
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample
1	0%	1360	1360	0.09	35	35	0.3%	0	0.0%	0.0000	37.86	2.6%
2	68%	1020	2380	0.15	270	86	1.1%	184	13.1%	0.0000	2.78	26.5%
3	65%	760	3140	0.20	215	75	1.9%	324	23.1%	0.3945	2.53	28.3%
4	50%	1900	5040	0.32	265	133	3.1%	456	32.6%	0.1621	6.17	13.9%
5	31%	1900	6940	0.44	135	93	4.0%	498	35.6%	0.0765	13.07	7.1%
6	15%	1895	8835	0.56	65	55	4.5%	508	36.3%	0.0355	28.15	3.4%
7	10%	2000	10835	0.68	65	59	5.1%	514	36.7%	0.0336	29.77	3.3%
8	6%	1915	12750	0.81	60	56	5.6%	518	37.0%	0.0323	30.92	3.1%
9	7%	2105	14855	0.94	75	70	6.3%	523	37.4%	0.0369	27.07	3.6%
10	11%	1940	16795	1.06	120	107	7.3%	536	38.3%	0.0659	15.17	6.2%
11	6%	2020	18815	1.19	125	118	8.4%	543	38.8%	0.0660	15.16	6.2%
12	7%	1910	20725	1.31	115	107	9.4%	551	39.4%	0.0641	15.61	6.0%
13	4%	2110	22835	1.44	110	106	10.4%	555	39.6%	0.0550	18.18	5.2%
14	4%	1930	24765	1.57	90	86	11.2%	559	39.9%	0.0489	20.44	4.7%
15	4%	1945	26710	1.69	100	96	12.1%	563	40.2%	0.0542	18.45	5.1%
16	4%	1860	28570	1.81	85	82	12.9%	566	40.4%	0.0479	20.88	4.6%
17	4%	1880	30450	1.92	85	82	13.7%	569	40.6%	0.0474	21.12	4.5%
18	3%	1930	32380	2.05	75	73	14.3%	571	40.8%	0.0404	24.73	3.9%

Figure 5.52 :Run 51 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected

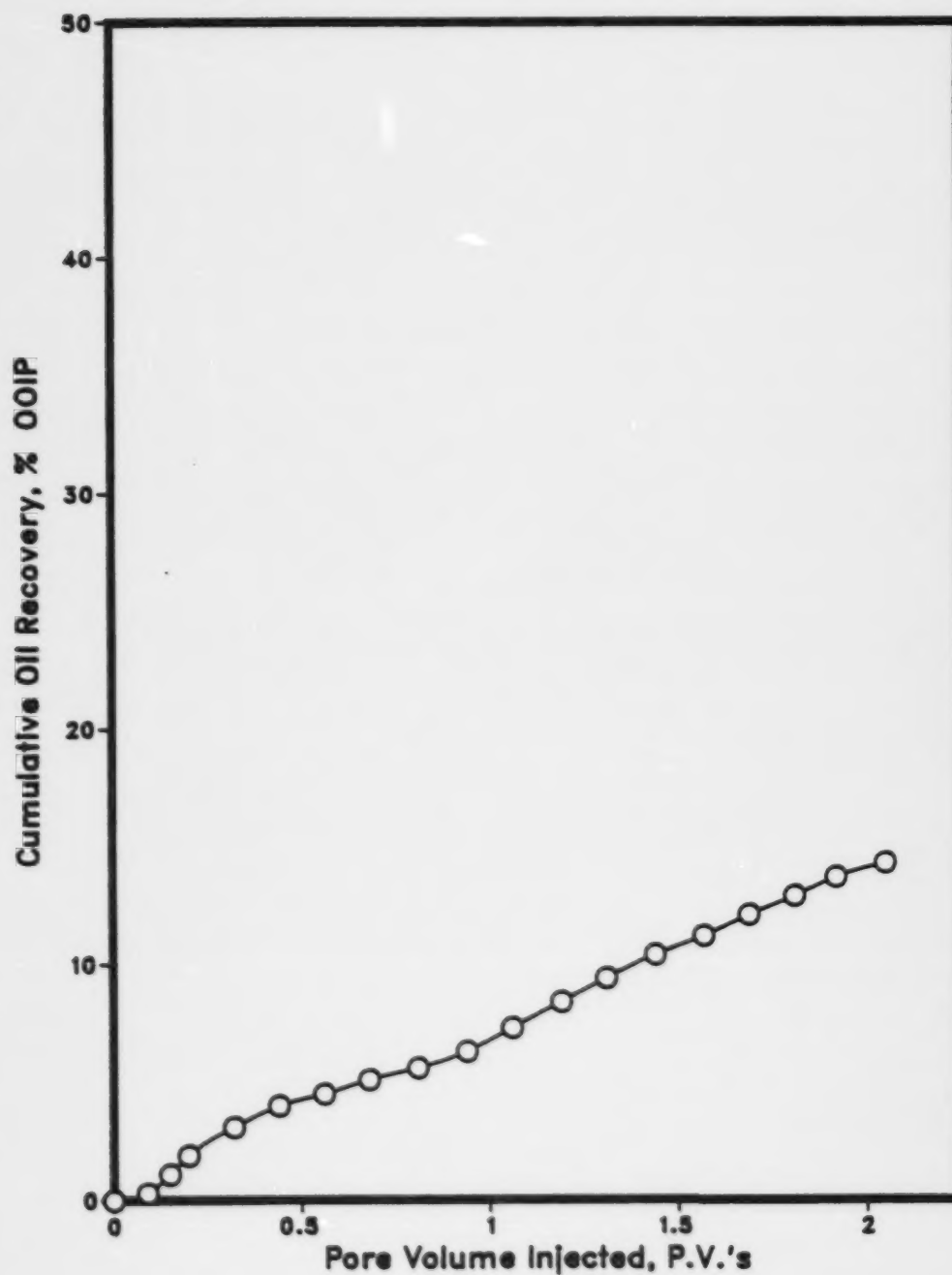


**Figure 5.53 :Run 51 Solventflood-Steamflood With Bottom Water
Oleic Phase in Each Sample Vs. Cumulative Volume Injected**

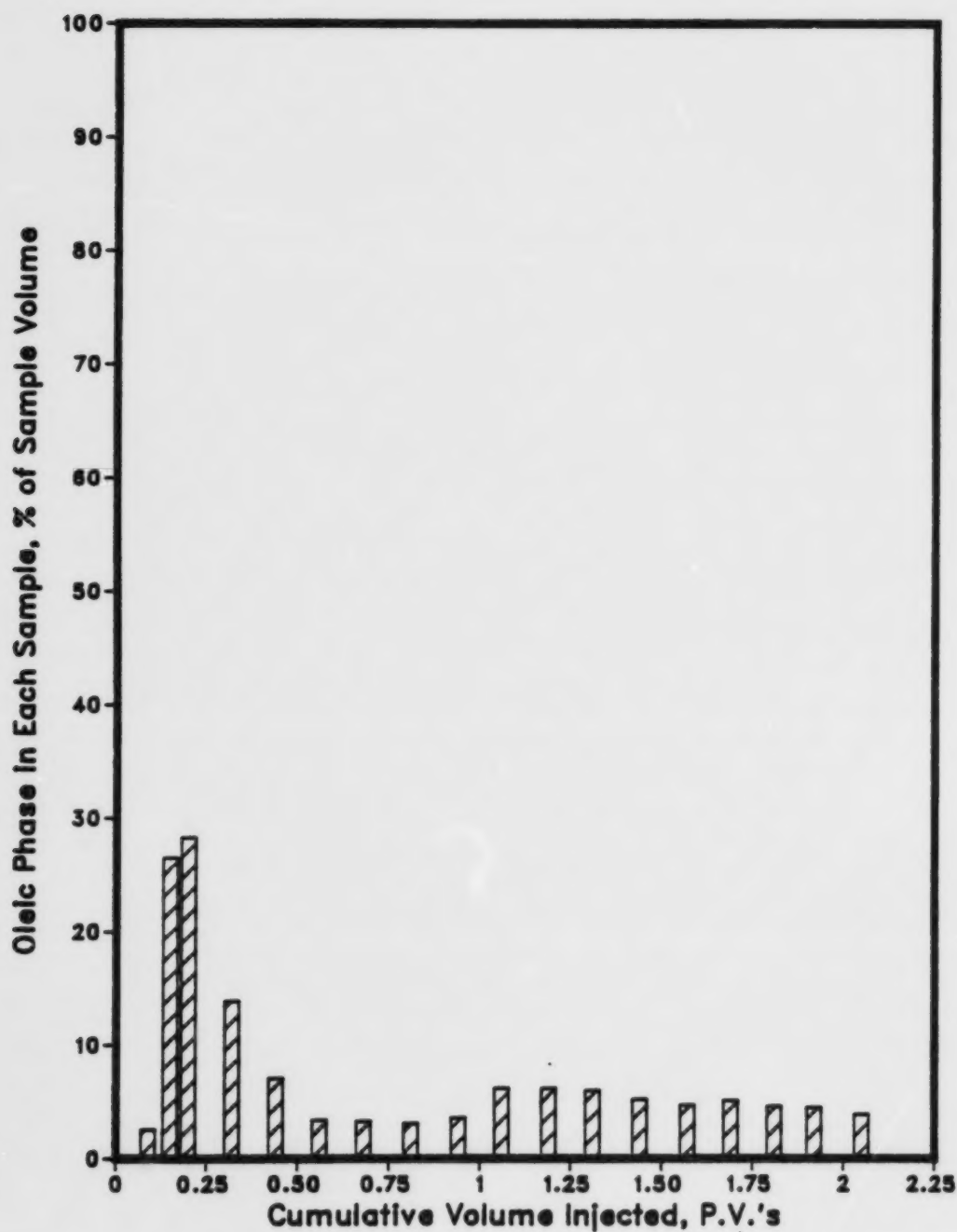


**Figure 5.54 :Run 51 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

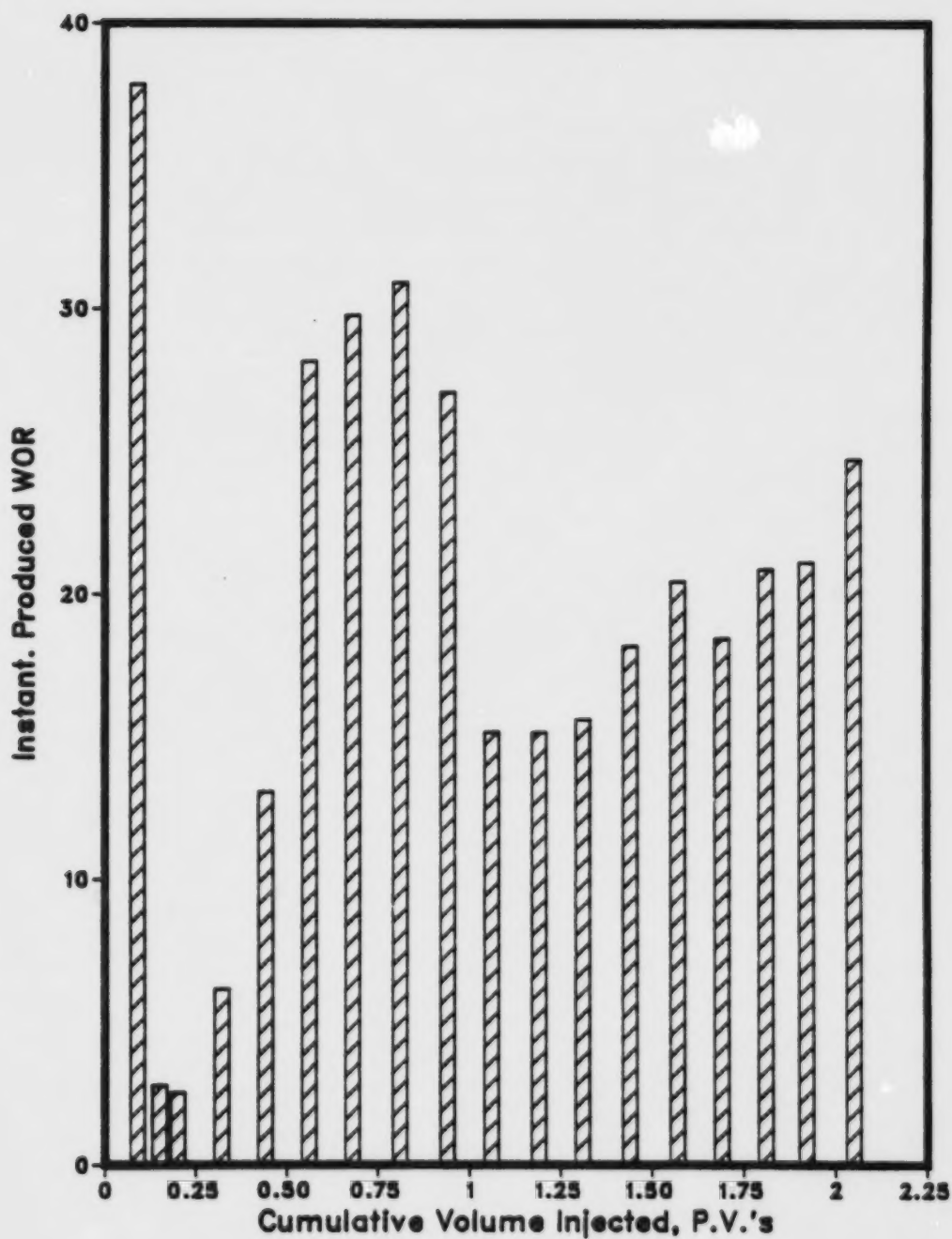


Figure 5.55 :Run 51 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced

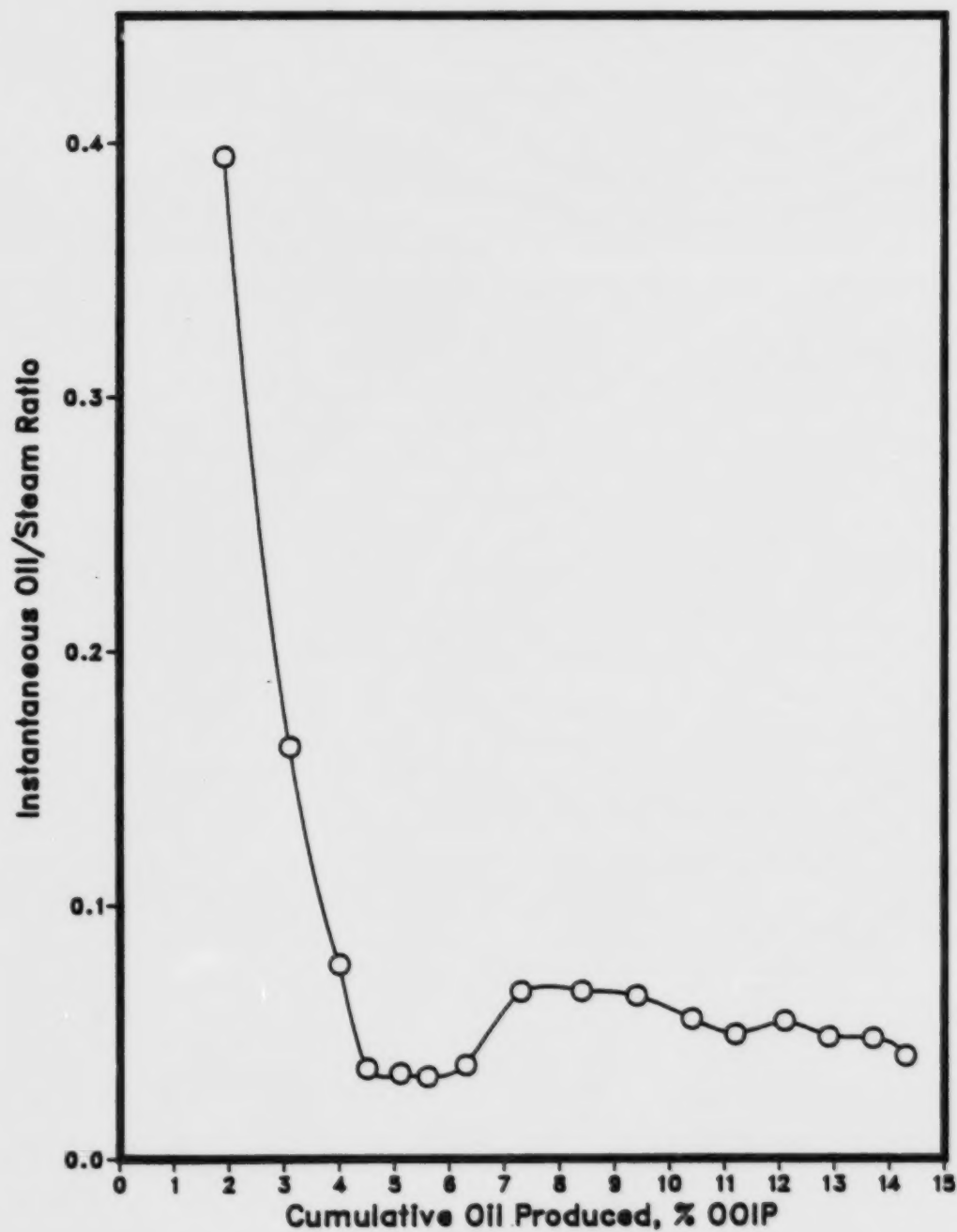


Table 5.15 : Run 53 Solvent-Steamflood With Bottom Water

HC Pore Volume :	11685.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15340.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	36.5%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	76.2%	Total Flow Rate of Steam :	229.20 cc/min
Initial H2O Satn. :	23.8%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	1400.0 cc (10.0% PV)	Bottom Water Thickness :	15.6 % (% Gross Model Thickness)
Steam Vol. Inj. :	31670.0 cc (2.06 PV)		

Net Oil Recovery : 19.0% Solvent Recovery : 54.4% Final Oil Saturation: 61.7%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P. V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	(%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	4%	1380	1380	0.09	80	77	77	0.7%	3	0.2%	0.0000	16.25	5.8%
2	67%	920	2300	0.15	740	244	321	2.7%	499	35.6%	0.0000	0.24	80.4%
3	50%	1100	3400	0.22	370	185	506	4.3%	684	48.9%	0.5068	1.97	33.6%
4	20%	1940	5340	0.35	210	168	674	5.8%	726	51.9%	0.1214	8.24	10.8%
5	7%	1810	7150	0.47	100	93	767	6.6%	733	52.4%	0.0585	17.10	5.5%
6	5%	2055	9205	0.60	100	95	862	7.4%	738	52.7%	0.0512	19.55	4.9%
7	4%	1980	11185	0.73	105	101	963	8.2%	742	53.0%	0.0560	17.86	5.3%
8	3%	1985	13170	0.86	110	107	1070	9.2%	745	53.2%	0.0587	17.05	5.5%
9	3%	2020	15190	0.99	125	121	1191	10.2%	749	53.5%	0.0660	15.16	6.2%
10	3%	2165	17355	1.13	135	131	1322	11.3%	753	53.8%	0.0665	15.04	6.2%
11	3%	1905	19260	1.26	155	150	1472	12.6%	758	54.1%	0.0886	11.29	8.1%
12	1%	2010	21270	1.39	125	124	1596	13.7%	759	54.2%	0.0663	15.08	6.2%
13	1%	1940	23210	1.51	110	109	1705	14.6%	760	54.3%	0.0601	16.64	5.7%
14	1%	2080	25290	1.65	105	104	1809	15.5%	761	54.4%	0.0532	18.81	5.0%
15	0%	2030	27320	1.78	125	125	1934	16.6%	761	54.4%	0.0656	15.24	6.2%
16	0%	1910	29230	1.91	105	105	2039	17.4%	761	54.4%	0.0582	17.19	5.5%
17	0%	1990	31220	2.04	100	100	2139	18.3%	761	54.4%	0.0529	18.90	5.0%
18	0%	1850	33070	2.16	80	80	2219	19.0%	761	54.4%	0.0452	22.13	4.3%

**Figure 5.56 :Run 53 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected**

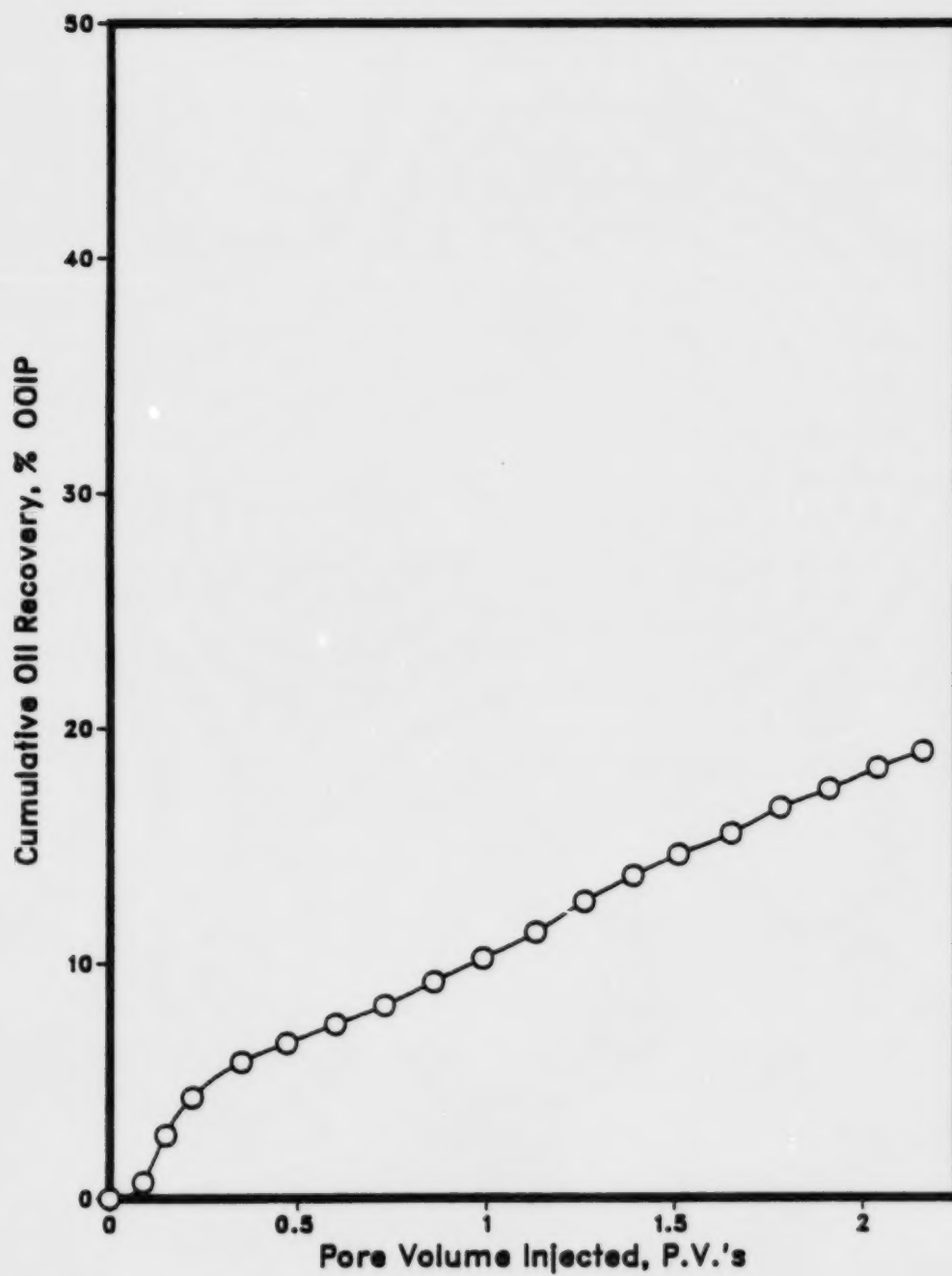


Figure 5.57 :Run 53 Solventflood-Steamflood With Bottom Water
Oleic Phase In Each Sample Vs. Cumulative Volume Injected

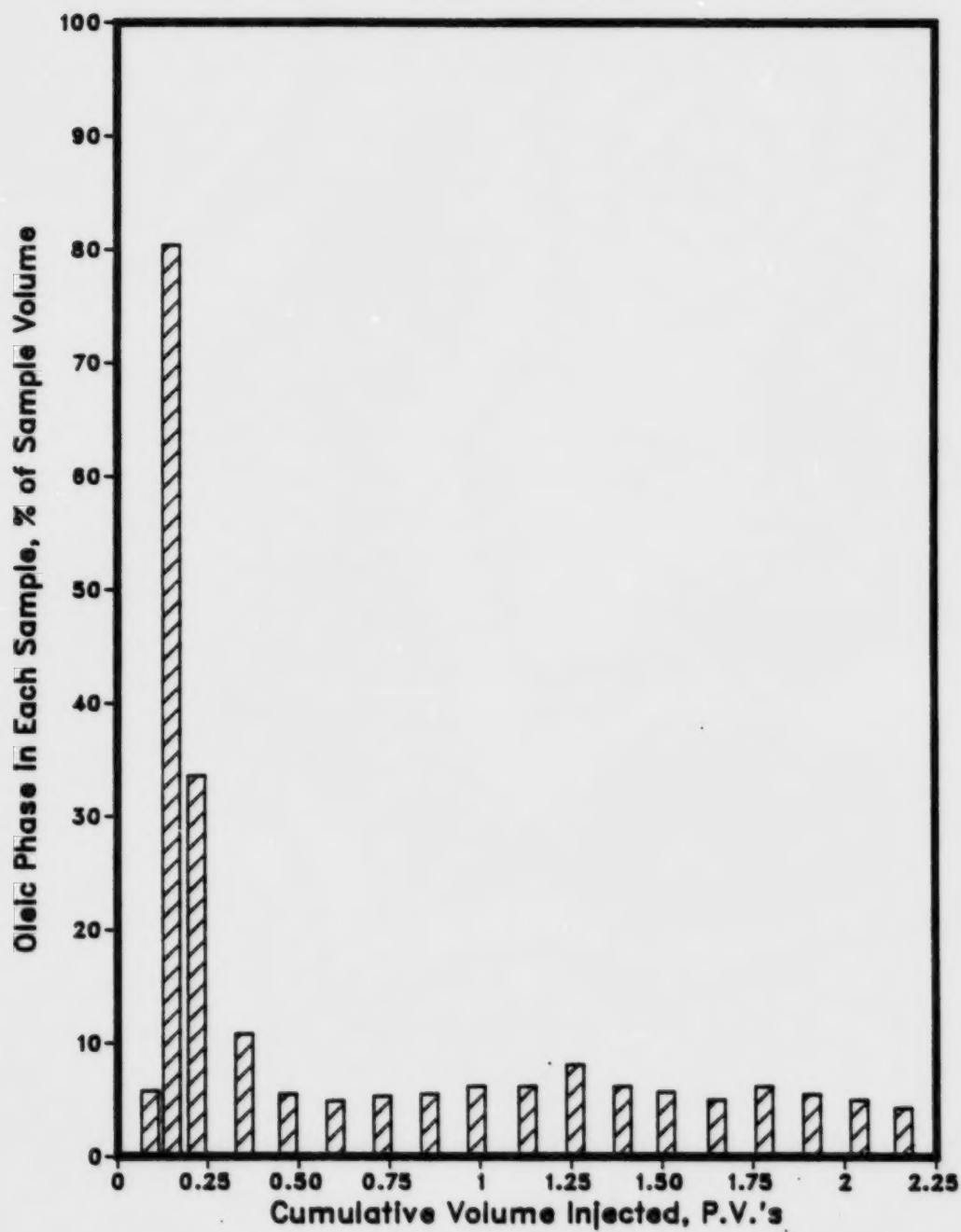


**Figure 5.58 :Run 53 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

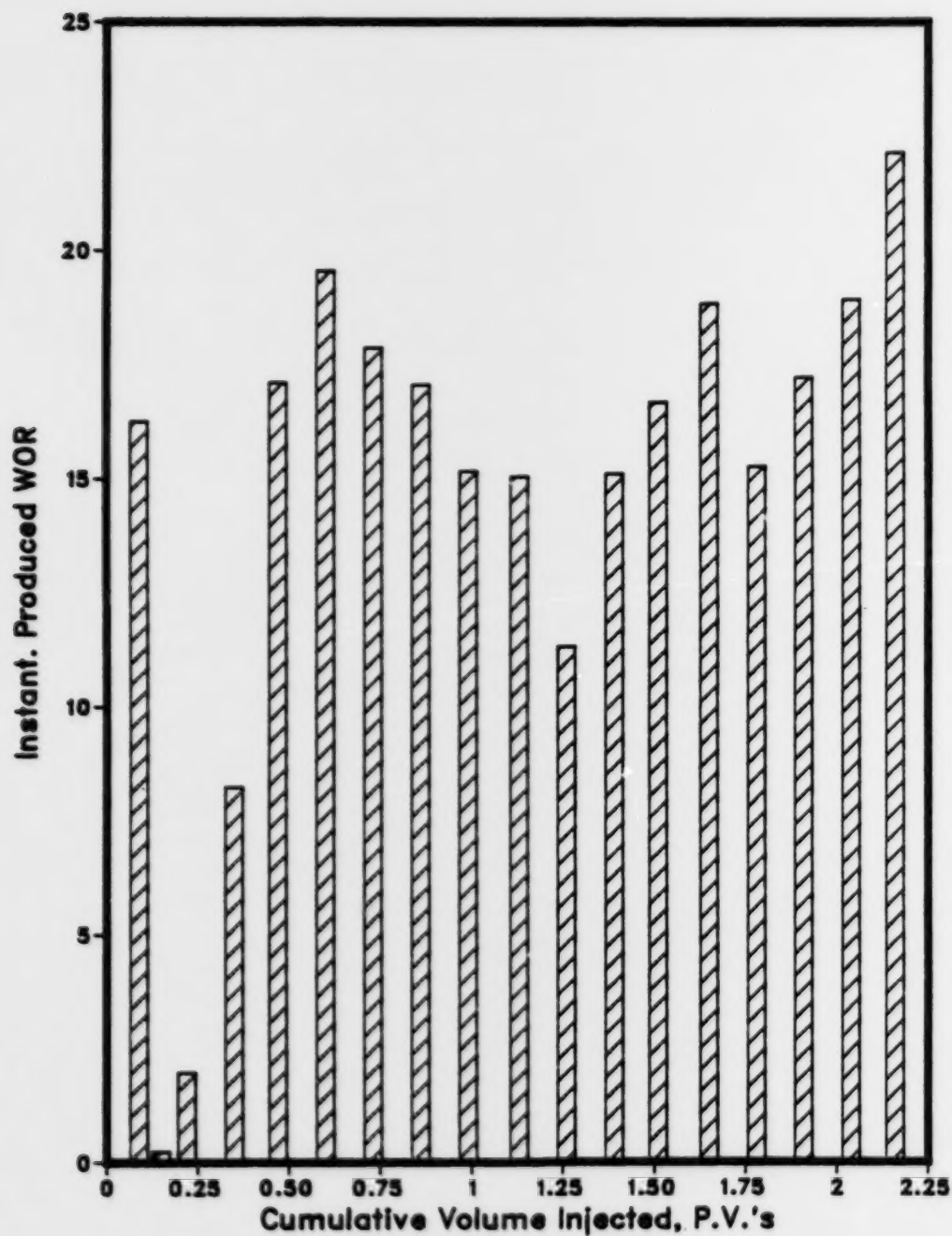


Figure 5.59 :Run 53 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

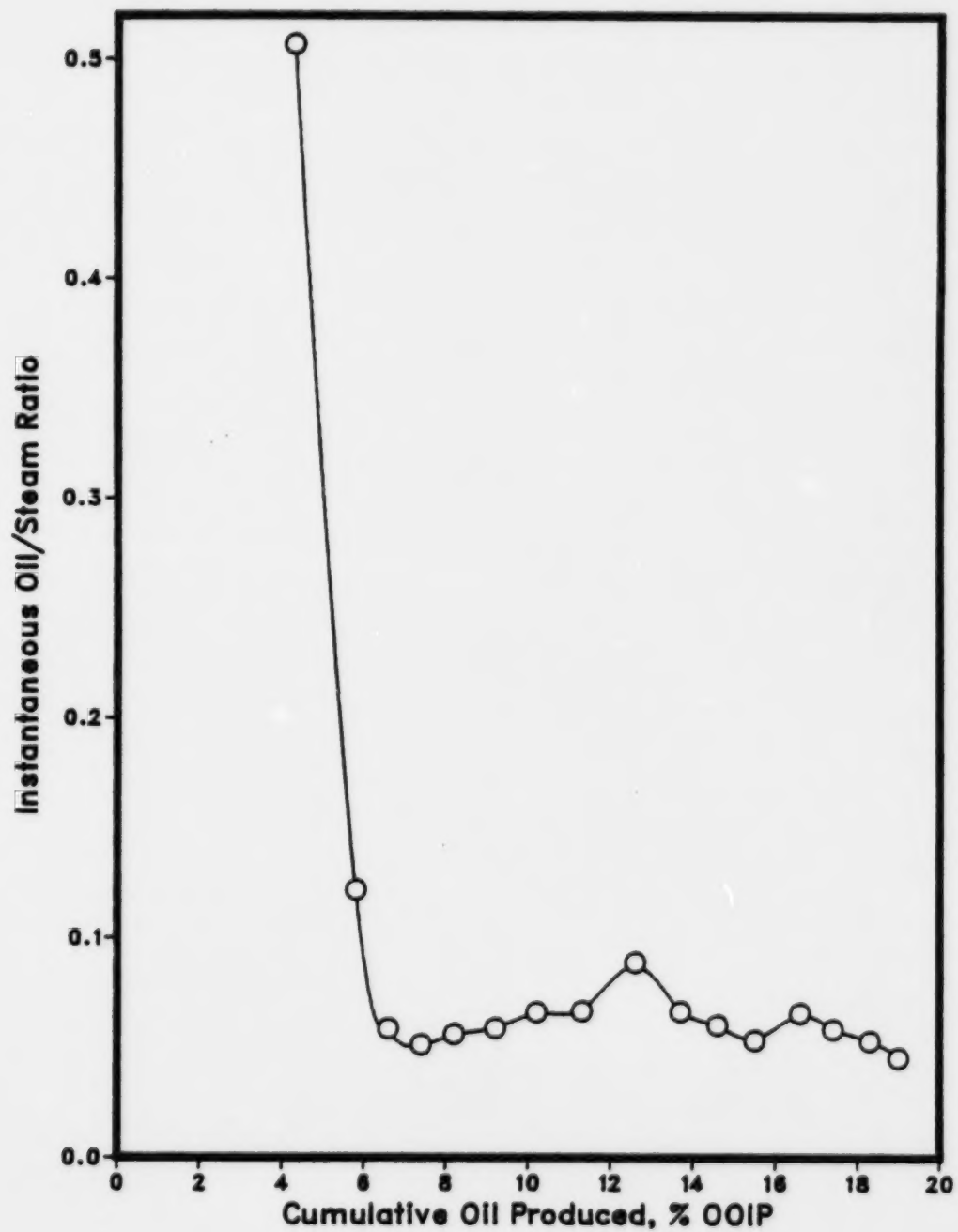


Table 5.16 : Run 54 Solvent-Steamflood With Bottom Water

HC Pore Volume :	13805.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15165.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	36.1%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	91.0%	Total Flow Rate of Steam :	229.20 cc/min
Initial H ₂ O Satn. :	9.0%	Solvent Flow Rate :	200.00 cc/min
Solvent Vol. Inj. :	1400.0 cc (10.0% PV)	Bottom Water Layer Thickness :	12.2 % (% Gross Thickness)
Steam Vol. Inj. :	31885.0 cc (2.10 PV)		

Net Oil Recovery : 22.6 %

Solvent Recovery : 89.8 %

Final Oil Saturation : 70.4 %

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	60%	1185	1185	1170	468	468	702	50.1%	0.0000	0.01	98.7%
2	59%	985	2170	750	308	776	1144	81.7%	0.0000	0.31	76.1%
3	27%	1175	3345	175	128	904	1191	85.1%	0.1750	5.71	14.9%
4	9%	1895	5240	630	573	1477	1248	89.1%	0.4980	2.01	33.2%
5	4%	2020	7260	165	158	1635	1255	89.6%	0.0889	11.24	8.2%
6	1%	1940	9200	175	173	1808	1257	89.8%	0.0992	10.09	9.0%
7	0%	2070	11270	150	150	1958	1257	89.8%	0.0781	12.80	7.2%
8	0%	1940	13210	130	130	2088	1257	89.8%	0.0718	13.92	6.7%
9	0%	2040	15250	120	120	2208	1257	89.8%	0.0625	16.00	5.9%
10	0%	1935	17185	110	110	2318	1257	89.8%	0.0603	16.59	5.7%
11	0%	1995	19180	110	110	2428	1257	89.8%	0.0584	17.14	5.5%
12	0%	1965	21145	95	95	2523	1257	89.8%	0.0508	19.68	4.8%
13	0%	2035	23180	85	85	2608	1257	89.8%	0.0436	22.94	4.2%
14	0%	1970	25150	145	145	2753	1257	89.8%	0.0795	12.59	7.4%
15	0%	2065	27215	105	105	2858	1257	89.8%	0.0536	18.67	5.1%
16	0%	1980	29195	85	85	2943	1257	89.8%	0.0449	22.29	4.3%
17	0%	1980	31175	75	75	3018	1257	89.8%	0.0394	25.40	3.8%
18	0%	2110	33285	105	105	3123	1257	89.8%	0.0524	19.10	5.0%

**Figure 5.60 :Run 54 Solvent-Steamflood With Bottom Water
Cumulative Oil Recovery Vs. Pore Volumes Injected**

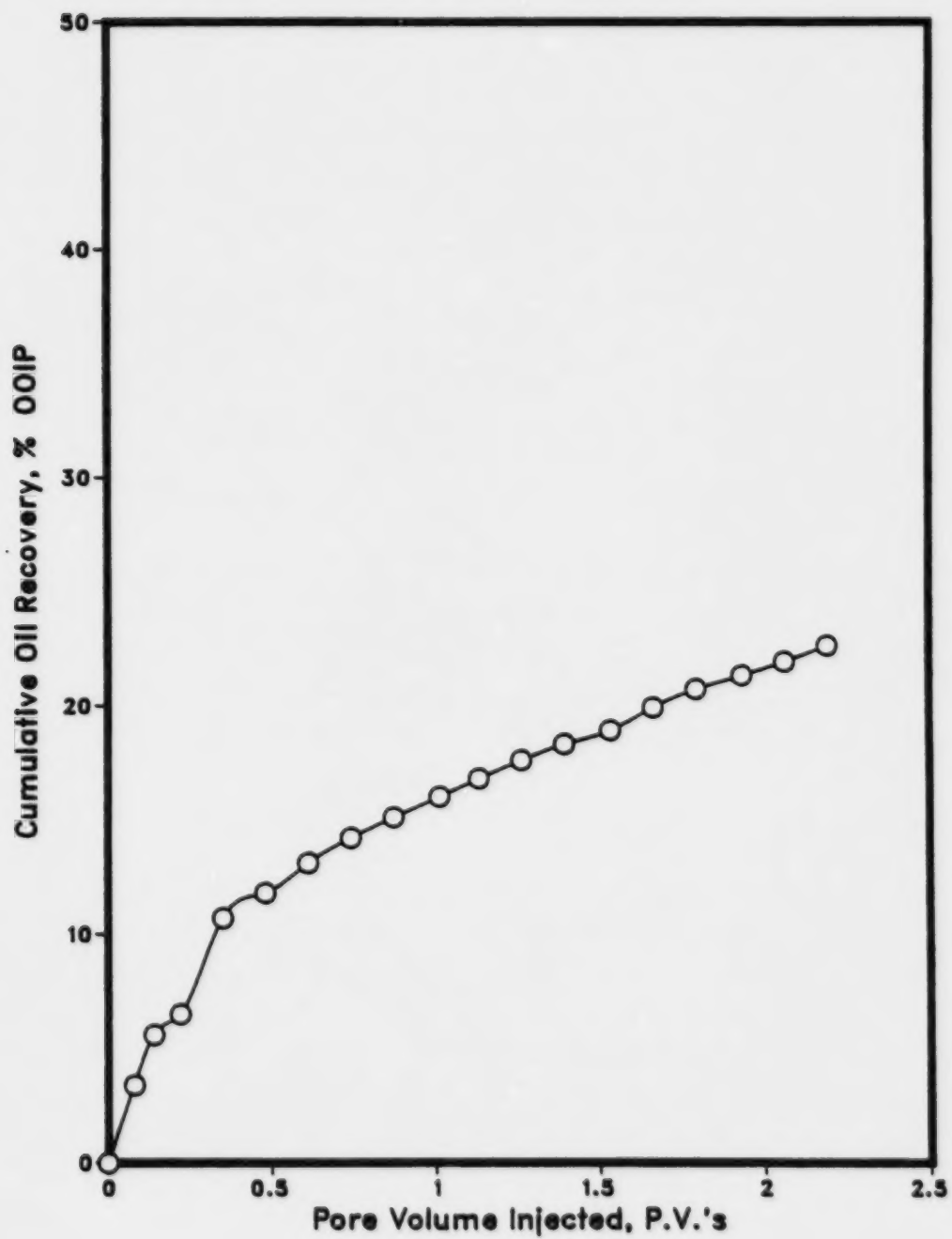


**Figure 5.61: Run 54 Solventflood—Steamflood With Bottom Water
Oleic Phase in Each Sample Vs. Cumulative Volume Injected**

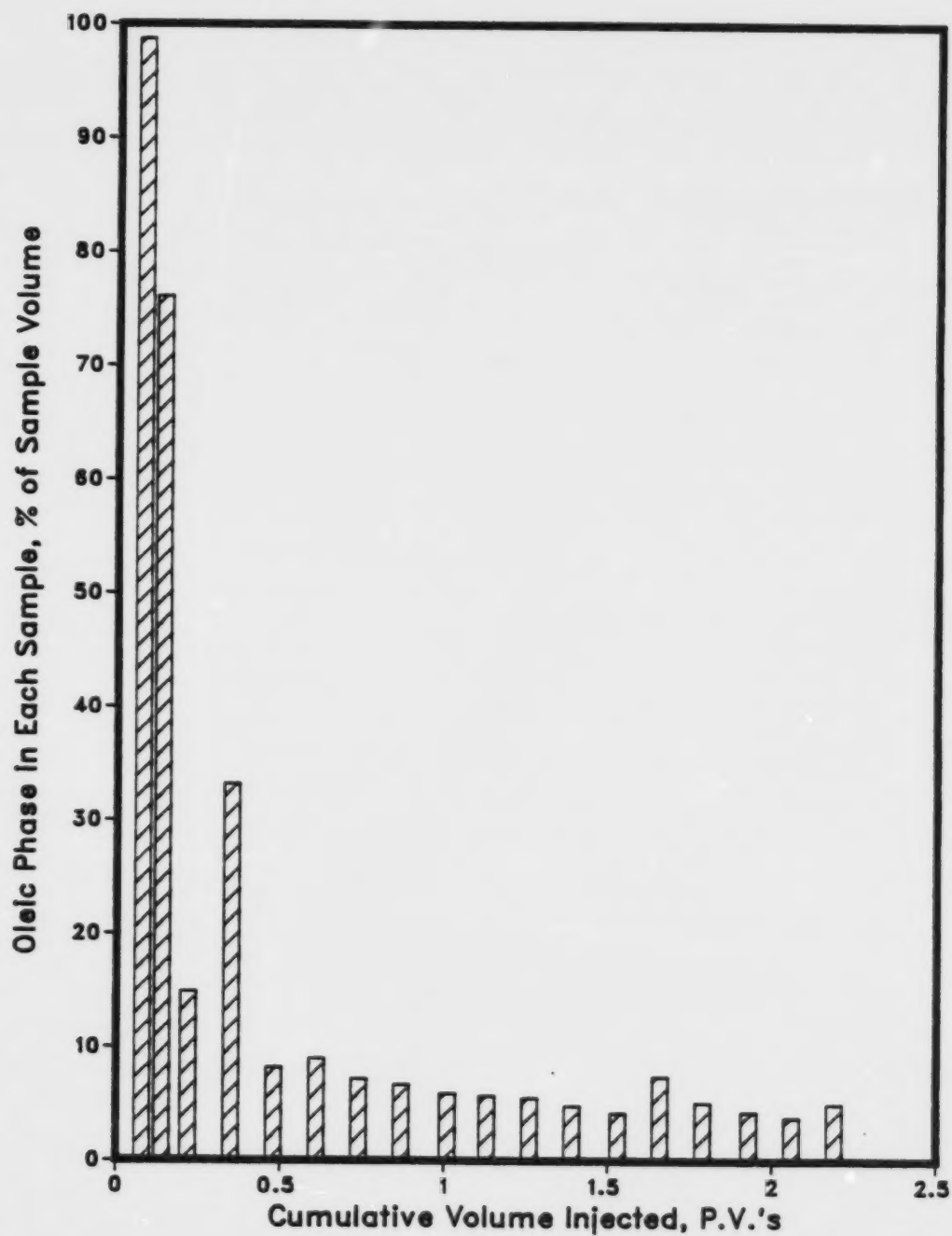


Figure 5.62: Run 54 Solvent-Steamflood With Bottom Water
Instantaneous Produced WOR Vs. Cumulative Volume Injected

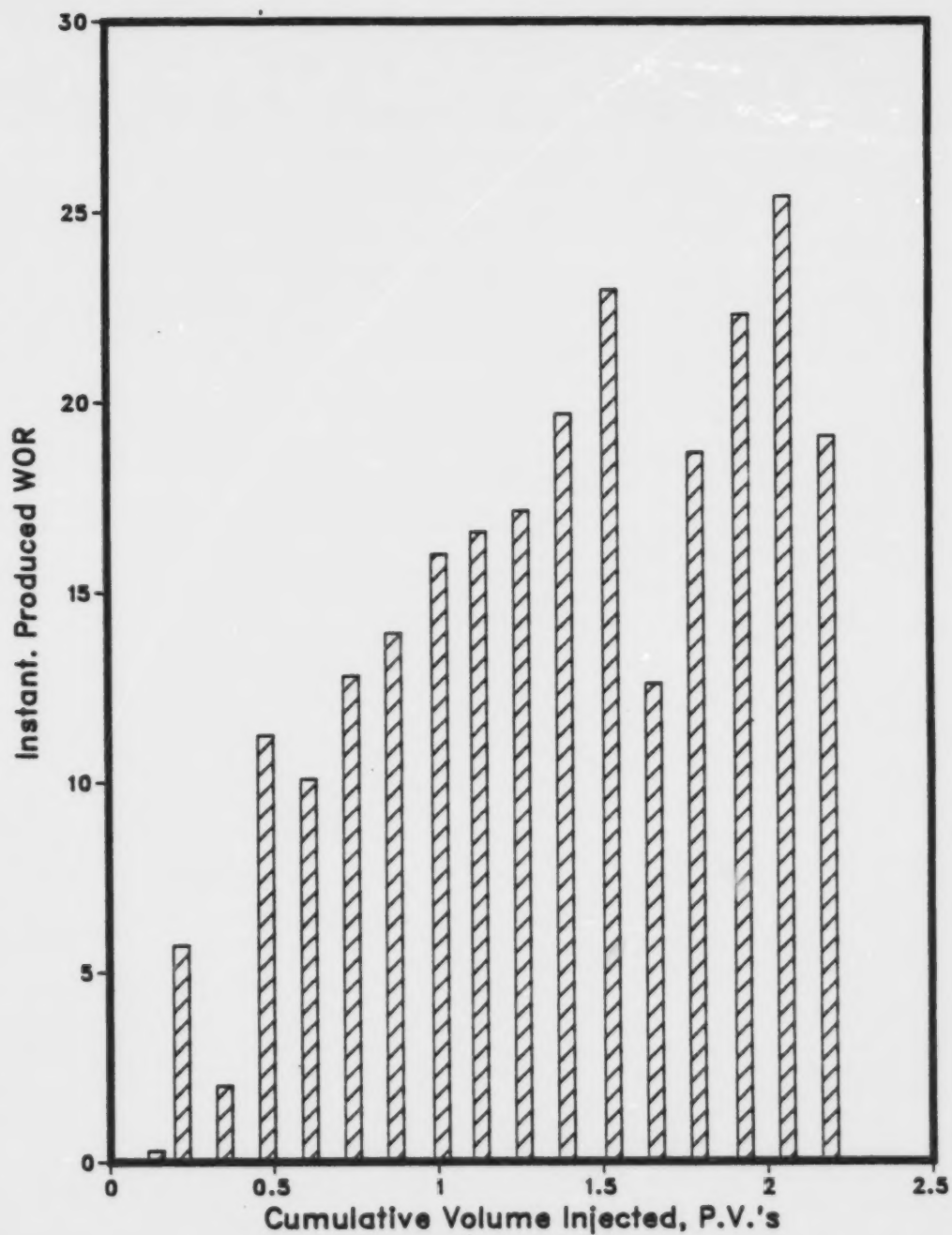
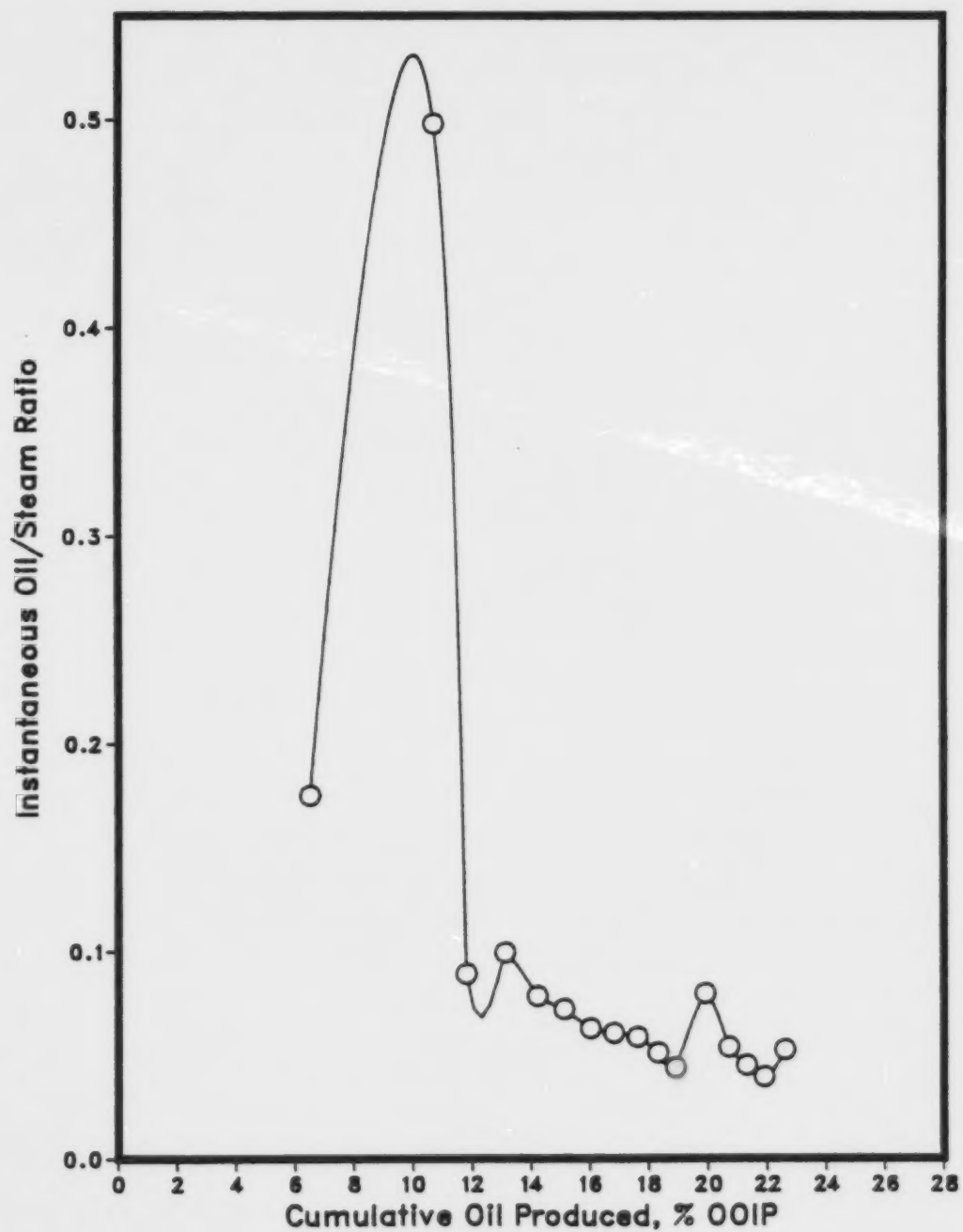


Figure 5.63 :Run 54 Solvent-Steamflood With Bottom Water
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced



water. At this point the steam displacement became less stable. The underriding of the oil zone by the steam is demonstrated in the temperature contours. Comparison of the all the temperatures profiles for the five runs revealed that the steam began to underride the oil layer sooner during Runs 51 and 53, due to the thicker bottom water layer of the two runs. The cross-sectional temperature profiles for Runs 49 (Fig. A.127-130), 50 (Fig. A.139-142) and 54 (Fig. A.175-A.178) also indicated that the heat advanced through the entire thickness of the model at about the same rate, whereas for Runs 51 (Fig. A.151-A.154) and 53 (Fig. A.163-A.166) heat advance was noticeably faster in the bottom water zone.

The solvent recoveries for Runs 49 (84.6%), 50 (88.5%) and 54 (89.8%) were considerably higher than those obtained in Runs 51 (40.8%) and 53 (54.4%). The solvent recoveries indicated that the higher the initial oil saturation in the core the better the solvent recovery. Since Runs 49, 50 and 54 had less bottom water and higher initial oil saturations than Runs 51 and 53, the solvent recoveries for these three runs were far better than those obtained for Runs 51 and 53.

The solvent recovery results were consistent with what Alikhan ⁶⁴ has reported. He stated that a solvent-steamflood process implemented in an oil saturated model yielded a greater solvent recovery than when performed in a waterflooded model. The nature of the solvent recovery in these two instances could be related to increased mixing of solvent with oil in the waterflooded situation which caused more solvent to remain in the model as a residual hydrocarbon saturation. The two instances of an initially oil saturated model and an initially waterflooded model could be considered analagous to a thin bottom water situation and a thicker bottom water case, respectively. The varying degree of oil-solvent mixing in the two different types of runs may have been a result of the solvent having a higher relative permeability in the thinner bottom water layer experiments than the thicker bottom water cases. The higher relative permeability would create more distinct solvent channelling and less mixing with the inplace oil thus a larger solvent recovery. For the thicker bottom water situation the difference in relative permeability between the water and

the solvent would be less than that for the thicker underlying water case due to the higher initial water saturation. The solvent would not flow through the model as easily thus blending more thoroughly with the in-place oil. Mixing of solvent and oil would be more pronounced in the thinner bottom water case. This would decrease the amount solvent recovered due to the remainder of a higher residual solvent slug material saturation.

The overall oil recoveries for Runs 49 (23.3% OOIP), 50 (25.4% OOIP), 51 (14.3% OOIP), 53 (19.0% OOIP) and 54 (22.6% OOIP) illustrate that bottom water can significantly reduce the amount of oil recovered by a solvent-steamflood. The effect of the bottom water on solvent and steam injection resulted in a considerably lower oil recovery than that obtained with a solvent-steamflood implemented on a homogeneous reservoir. Results of Runs 49, 50, 51, 53 and 54 confirm that the use of a solvent slug assisted in improving the overall oil recovery by partially diverting the steam away from the bottom water and into the oil layer during the initial stages of the steamflood. It was also noted that the bottom water had a more detrimental effect on the overall oil recovery as it increased in thickness. Figure 5.64, a plot of oil recovery after two pore volumes injected versus bottom water thickness for the five experiments as well as Run 46 (solvent-steamflood without bottom water), demonstrates the effect varying bottom water thickness has on overall oil recovery. Figure 5.64 is similar to the plot created in the study by Proctor, George and Farouq Ali ⁶³ which investigated conventional steamflooding of thin bottom water formations without the use of a solvent. Similarly to what was reported by Proctor, George and Farouq Ali ⁶³, Figure 5.64 indicates that for bottom thicknesses less than approximately 10% of the gross model thickness, the oil recovery due to the solvent-steamflood process is close to that obtained by solvent-steamfloods implemented in homogeneous models. For bottom water thicknesses greater than about 10% of the total model thickness the overall oil recovery of the solvent-steamflood process is greatly reduced. The experimental results suggest that the injection of a solvent slug prior to steamflooding a bottom water reservoir could improve the overall oil recovery up until a

limiting bottom water thickness is reached. Based upon Figure 5.64 the limiting bottom water thickness is estimated to be somewhere between 25 and 30% of the total model thickness. It is concluded that as the bottom water thickness increases in the model the oil recovery is decreased until a limiting bottom water thickness value is reached, above which the use of a solvent slug does not significantly improve the oil recovery.

One of the major objectives of this study was to investigate the use of solvents in combination with steam as a recovery method for marginal heavy oil reservoirs containing bottom water and/or a gas cap. Solvent injection into the oil layer during the initial period of the runs created a temporary preferential path for the steam to follow, preventing the steam from immediately channelling into the bottom water. The steam progressed through the oil layer for a short period of time until it finally moved downward and advanced through the bottom water section. Once the steam moved into the bottom water layer the heating efficiency dropped in the oil zone and a severe drop in the overall oil recovery resulted.

Comparison of the results of Runs 49, 50 and 54 with previous continuous steamfloods (Runs 32, 33 & 39) carried out with similar bottom water thicknesses, revealed that the solvent slug injection prior to steamflooding partially alleviated the effect of bottom water and resulted in improved oil recovery. Due to partial diversion of the steam into the solvent channels in the oil region the steam displacement achieved was more stable, causing a delayed and more pronounced steam breakthrough to occur at the production well. In the case of a conventional steamflood, the bottom water had a greater and more immediate effect on steam displacement resulting in a much less stable displacement. This led to earlier and less distinct steam breakthrough at the producer. Oil recovery results for Runs 32 (BW=2.3%), 33 (BW=4.0%) and 39 (BW=12.5%) were 22.8%, 22.9% and 16.8% of the original oil in place, respectively. These recoveries were appreciably less than the recoveries yielded by Runs 49 (23.3% OOIP), 50 (25.4% OOIP), 53 (19.0% OOIP) and 54 (22.6% OOIP). In the case of Run 51 there did not seem to be

Figure 5.64 :Total Oil Recovery versus Bottom Water Thickness For Solvent-Steamfloods

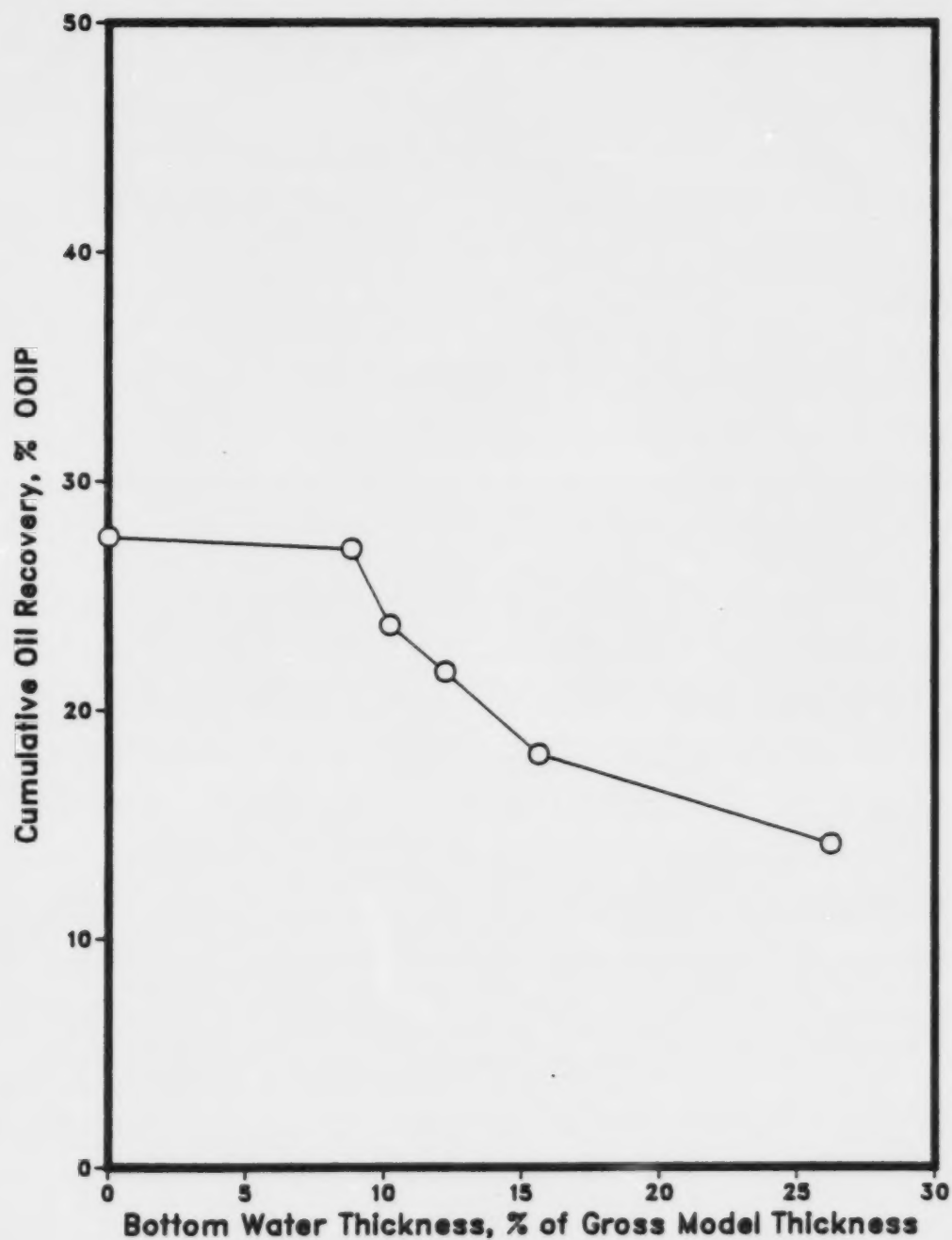
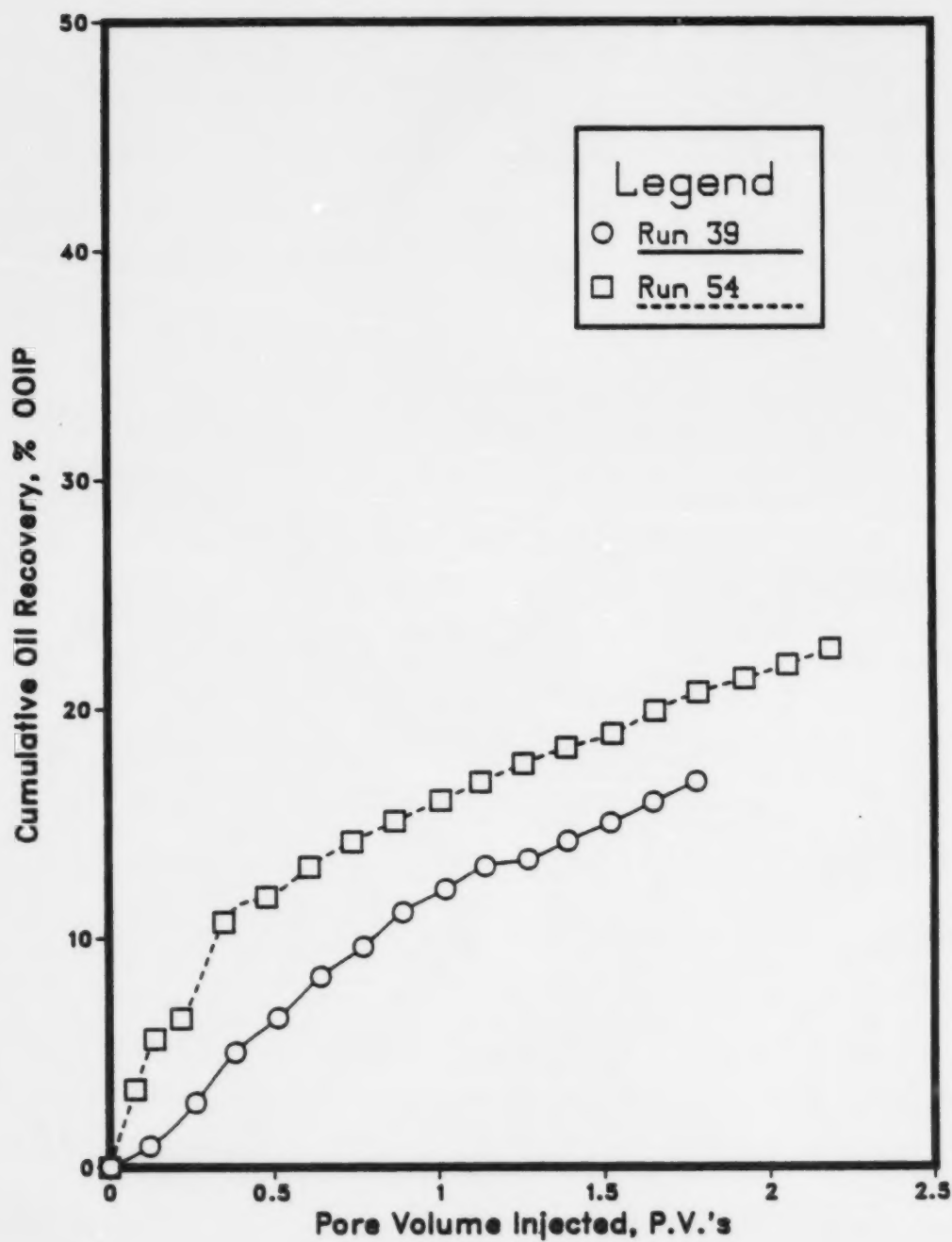


Figure 5.65 : Comparison of Steamflood Run 39 & Solvent-Steamflood Run 54 Recoveries Performed in a Bottom Water Model



an improvement in the oil recovery compared to the Runs 32, 33 and 39. Because of the extensive bottom water layer in Run 51 the steam was not able to flow through the oil layer for as long as in Runs 49, 50, 53 and 54 resulting in a considerable decline in the oil recovery of Run 51. Comparing the results of the two different types of experiments (ie. steamflood versus solvent-steamflood) revealed that the solvent-steamflood does exhibit an improved oil recovery capability from bottom water formations in relation to a conventional steamflood. A crossplot of the recovery curves for Runs 39 and 54 is provided in Figure 5.65 which compares the effectiveness of a solvent-steamflood process as opposed to a steamflood in similar bottom water formations. The difference in the initial behaviour of these two curves demonstrates the effectiveness of the solvent slug. The recovery curve for Run 54 in the primary stages of the run rises sharply compared to the recovery curve of Run 39. This was due to solvent channelling in Run 54 allowing the steam to penetrate the oil zone more easily which increased the stability of the steam displacement of oil in the model and resulted in more oil being mobilized and subsequently recovered. Figure 5.65 illustrates the increased oil recovery potential of the solvent-steamflood process over a conventional steamflood in bottom water formations.

It is concluded from the results of Runs 32, 33, 39, 49, 50, 51, 53 and 54 that the solvent slug assisted in improving the overall oil recovery in bottom water formations by partially diverting the steam away from the bottom water zone during the initial stages of the steamflood.

Role of Gas Injection in Steamflooding

In this research study, three different types of runs were conducted using gas injection prior to the specific recovery method being investigated. The first type of run involved gas injection prior to steam injection in a bottom water model and was discussed in the previous section dealing with base experiments. The second type of experiment conducted gas injection prior to a solvent-steamflood of a homogeneous model and the final

type of run performed a solvent-steamflood in a bottom water model. The purpose for carrying out these gas injection runs was based on the principle reasoning that the injected gas would create a gas cap or channel in the upper portion of the model which would form a more conductive path for the injected fluid (ie. solvent and/or steam) to enter the oil zone. The less resistant gas path would aid in partially diverting the injected fluid away from the bottom water so that the oil mobilizing properties of the injected fluids could be used more effectively to recovery the overlying oil.

Proctor, George and Farouq Ali⁶³ performed a set of experiments (Runs 24 & 25) in the same low pressure model of the Aberfeldy formation as was used in the present research investigation. These two runs involved gas injection proceeded by a steamflood of a homogeneous model. The results reported by Proctor et al.⁶³ are briefly described in the proceeding section.

The first set of gas runs (Runs 60 & 61) carried out in the present research study were base experiments which involved creating a gas zone in a bottom water model before performing a steamflood. The results of these two experiments have already been discussed in the previous base experiment section "Steamflood of a Bottom Water Model With Prior Gas Injection". However, a brief summary of the results of the two experiments will be included in the following section.

The next group of experiments (Runs 55 & 56) utilized gas injection prior to conducting a solvent-steamflood of a homogeneous model, with the results provided and interpreted in the preceding section.

During the final set of runs (Runs 58, 59 & 62) gas injection was performed prior to the solvent-steamflood of a bottom water model. The results and discussion of the these three gas injection experiments are also included in this section.

Gas Injection in a Steamflood

Proctor, George and Farouq Ali ⁶³ suggested that the injection of a small amount of inert gas prior to steamflooding may result in a flow channel away from the bottom water zone, thus minimizing the heat scavenging effect of the bottom water zone. They first tested this idea in a homogeneous pack and found that the implementation of gas injection may also be suitable in formations without the presence of bottom water. The gas injection strategy had the advantage of drastically increasing the steam injectivity in the oil region and therefore, could be quite useful in formations where steam injectivity is very low in the oil zone. It was also reported that the production response for the gas injection process was slightly less than that obtained for a continuous steam injection scheme. However, for a formation where steam injectivity is low, the increase in injectivity due to gas injection may justify the slight drop in the initial oil production response.

Gas Injection Prior to Steam Injection with Bottom Water

Results of Runs 60 and 61 indicated that the existence of a gas region in a bottom water model during a steamflood helped to partially divert the injected steam into the oil zone away from the bottom water so that the steam could be used more efficiently to heat and displace the oil in the model. When comparing the results of Run 39 (steamflood of a bottom water model) and Run 61 (gas injection prior to a steamflood of a bottom water model), which had similar bottom water thicknesses, it was evident during Run 61 that the presence of a gas zone in the model resulted in an improvement in the initial recovery response of a steamflood process in a bottom water formation. Also in Run 61, time until steam breakthrough was prolonged and steam breakthrough was more distinct than in Run 39, as indicated by the differences between the comparative plots generated from the results of each experiment. This was due to the gas zone partially preventing the steam from being lost to bottom water zone and therefore the steam could more effectively mobilize and recover the in-place oil.

Gas Injection with Solvent and Steam Injection

By injecting a small value of inert gas before performing a solvent-steamflood it is believed that a flow channel can be created which would divert the injected solvent and steam away from the bottom water region and into the oil zone. This would further minimize the heat scavenging effects of the bottom water zone. The process of gas injection in combination with a solvent-steamflood was first performed in a homogeneous model. Runs 55 and 56 consisted of creating a gas cap in a homogeneous model prior to a solvent-steamflood which used a 10% pore volume slug of solvent. The initial gas saturation in the model for the two runs was 0.6%. Tables 5.17 and 5.18 contain the tabulated results for Runs 55 and 56, respectively.

The oil recovery curves of Runs 55 and 56 are shown in Figures 5.66 and 5.70, respectively. Both curves rise sharply during the initial stages of the experiments which represent the production of oil mobilized by the solvent slug and steam. Following the sharp increase the curves begin to level off slightly and soon after started to rise again. However, the rise was less drastic than the initial increase. These regions of the recovery curves represent steam breakthrough at the production well which was preceded by the continued mobilization of oil due to steam injection. Figures 5.66 and 5.70 were similar to the recovery curves obtained for the straight solvent-steamfloods performed in a homogeneous model (Runs 44, 45 & 46).

The bar graphs of volume as a percentage of oleic phase in each sample taken versus cumulative volume injected and instantaneous produced WOR versus cumulative volume injected for Runs 55 (Fig. 5.67-5.68) and 56 (Fig. 5.71-5.72) indicate that steam breakthrough occurred in the primary stages of both experiments. The peaks and valleys of these bar plots corresponded very closely with the respective recovery curves. Again the plots were quite similar in nature to those of Runs 44, 45 and 46.

Figures 5.69 and 5.73 are plots of instantaneous oil/steam ratio versus cumulative oil produced for Runs 55 and 56, respectively. Initially the oil/steam ratio drops steeply and then a distinct peak in the oil/steam ratio occurs in both figures between approximately 10 to 20% production of the original oil in place. Oil produced due to the steam sweeping the model prior to initial steam breakthrough was represented by this peak in the oil/steam ratio plots. The gradual levelling of the curves after the peak was created by further mobilizing of oil by the steam after breakthrough.

As in the case of Runs 44, 45 and 46, the temperature profiles for Runs 55 (Fig. A.179-A.186) and 56 (Fig. A.191-A.198) indicated that the solvent and steam advanced faster through the upper level of the model than the lower section. By comparing the profiles of Runs 44, 45 and 46 to those of Runs 55 and 56 it appeared that the injected solvent and steam moved slightly faster through the upper portion of the model when a gas saturation existed. The injectivity of the solvent and steam in the model was improved due to the existence of the gas saturation which resulted in the solvent and steam progressing more rapidly through the upper portion of the reservoir than the lower region. The cross-sectional temperature profiles for Runs 55 (Fig. A.187-A.190) and 56 (Fig. A.199-A.202) agreed with the top view profiles in that the solvent and steam advanced faster through the upper portion of the model than the lower part.

The oil recoveries for Runs 55 (26.8%) and 56 (27.0%) were fairly close to one another. These results were much the same due to the similarities in porosities and initial saturations for both experiments. The overall oil recovery for continuous steamfloods performed in a homogeneous model were slightly better than the oil recoveries achieved by Runs 55 and 56. The slight drop in oil recovery was probably due the gas cap partially diverting the steam over top of the oil and resulting in less oil being contacted by the solvent and steam. Solvent recoveries for Runs 55 (87.7%) and 56 (90.9%) were quite favourable due to the solvent flowing to the production well over top of the oil in the gas channel. The larger solvent recoveries were also due to the high initial oil saturations in

both experiments. The reason for this solvent recovery behaviour was discussed earlier in the chapter.

During Runs 55 and 56 the solvent and steam tended to partially override the oil zone through the lower resistance "gas cap". Therefore the solvent and steam could not penetrate the oil zone as effectively as when a gas cap was not present (Runs 44, 45 & 46). This resulted in a slightly lower oil recovery for the two experiments as compared to Runs 44, 45 and 46. It was noted from the experimental results of Runs 55 and 56 that the presence of a gas cap slightly decreased the overall oil recovery. Figure 5.74 provides a comparison of the recovery curves for a solvent-steamflood of a homogeneous model (Run 45) and a solvent-steamflood preceding gas injection in a homogeneous model (Run 56). An examination of Figure 5.74 shows little difference between the two experiments except that the oil recovery for Run 45 (30.0% OOIP) was slightly higher due to a more stable displacement by the steam more thoroughly penetrating the oil zone through the channels formed by the viscous fingering of the injected solvent. The recovery for Run 56 (27.0% OOIP) was a bit less since the solvent and steam had a tendency to override the oil zone into the gas channel resulting in less solvent and oil penetrating, mobilizing and displacing the in-place oil. Run 45 was able to more effectively use the heating characteristics of the steam to recover the oil in the model.

This study deals with bottom water reservoirs, and therefore the presence of a gas cap would aid in diverting the injected solvent and steam away from the underlying bottom water layer. From the results of the two experiments it is concluded that the injection of a small amount of an inert gas prior to a solvent-steamflood would create a flow channel away from the bottom water zone and thus minimize the heat scavenging nature of the underlying bottom water layer. Also a comparison of Runs 55 and 56 to Runs 44, 45 and 46 revealed that the production response of the gas injection process was slightly lower than that for the straight solvent-steamflood process. However, in a reservoir where

Table 5.1.7: Run 55 Gas Injection Prior to Solvent-Steamflood of Homogeneous Model

HC Pore Volume : 13015.0 cc
 Pore Volume : 14410.0 cc
 Bulk Volume : 42005.0 cc
 Porosity : 34.3%
 Initial Oil Satn. : 90.3%
 Initial H₂O Satn. : 9.1%
 Initial Gas Satn. : 0.6%
 Solvent Vol. Inj. : 1400.0 cc

Type of Oil Used : Faxam-100
 Initial Model Temperature : 3.00 C
 Water Feed Flow Rate : 200.00 cc/min
 Boiler Feed Flow Rate : 29.20 cc/min
 Total Flow Rate of Steam : 229.20 cc/min
 Solvent Flow Rate : 200.00 cc/min
 Gas Cap Volume : 85.0 cc
 Steam Vol. Inj. : 32690.0 cc (2.27 PV)

Net Oil Recovery : 26.8%

Solvent Recovery : 87.7%

Final Oil Saturation : 66.1%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	64%	1000	1000	1000	360	360	2.8%	45.7%	0.0000	0.00	100.0%
2	63%	1005	2005	700	259	619	4.8%	77.2%	0.0000	0.44	69.7%
3	25%	1500	3505	220	165	784	6.0%	81.1%	0.1719	5.82	14.7%
4	12%	2140	5645	180	158	942	7.2%	82.7%	0.0918	10.89	8.4%
5	8%	2085	7730	205	189	1131	8.7%	83.9%	0.1090	9.17	9.8%
6	7%	1865	9595	180	167	1298	10.0%	84.8%	0.1068	9.36	9.7%
7	5%	2090	11685	195	185	1483	11.4%	85.5%	0.1029	9.72	9.3%
8	4%	1965	13650	205	197	1680	12.9%	86.1%	0.1165	8.59	10.4%
9	3%	2055	15705	265	257	1937	14.9%	86.6%	0.1480	6.75	12.9%
10	2%	1955	17660	295	289	2226	17.1%	87.1%	0.1777	5.63	15.1%
11	2%	2035	19695	330	323	2549	19.6%	87.6%	0.1935	5.17	16.2%
12	1%	2015	21710	225	223	2772	21.3%	87.7%	0.1257	7.96	11.2%
13	0%	2105	23815	170	170	2942	22.6%	87.7%	0.0879	11.38	8.1%
14	0%	2010	25825	135	135	3077	23.6%	87.7%	0.0720	13.89	6.7%
15	0%	2095	27920	145	145	3222	24.8%	87.7%	0.0744	13.45	6.9%
16	0%	2070	29990	90	90	3312	25.4%	87.7%	0.0455	22.00	4.3%
17	0%	2060	32050	100	100	3412	26.2%	87.7%	0.0510	19.60	4.9%
18	0%	2040	34090	80	80	3492	26.8%	87.7%	0.0408	24.50	3.9%

Figure 5.66 :Run 55 Gas Injection Prior to Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

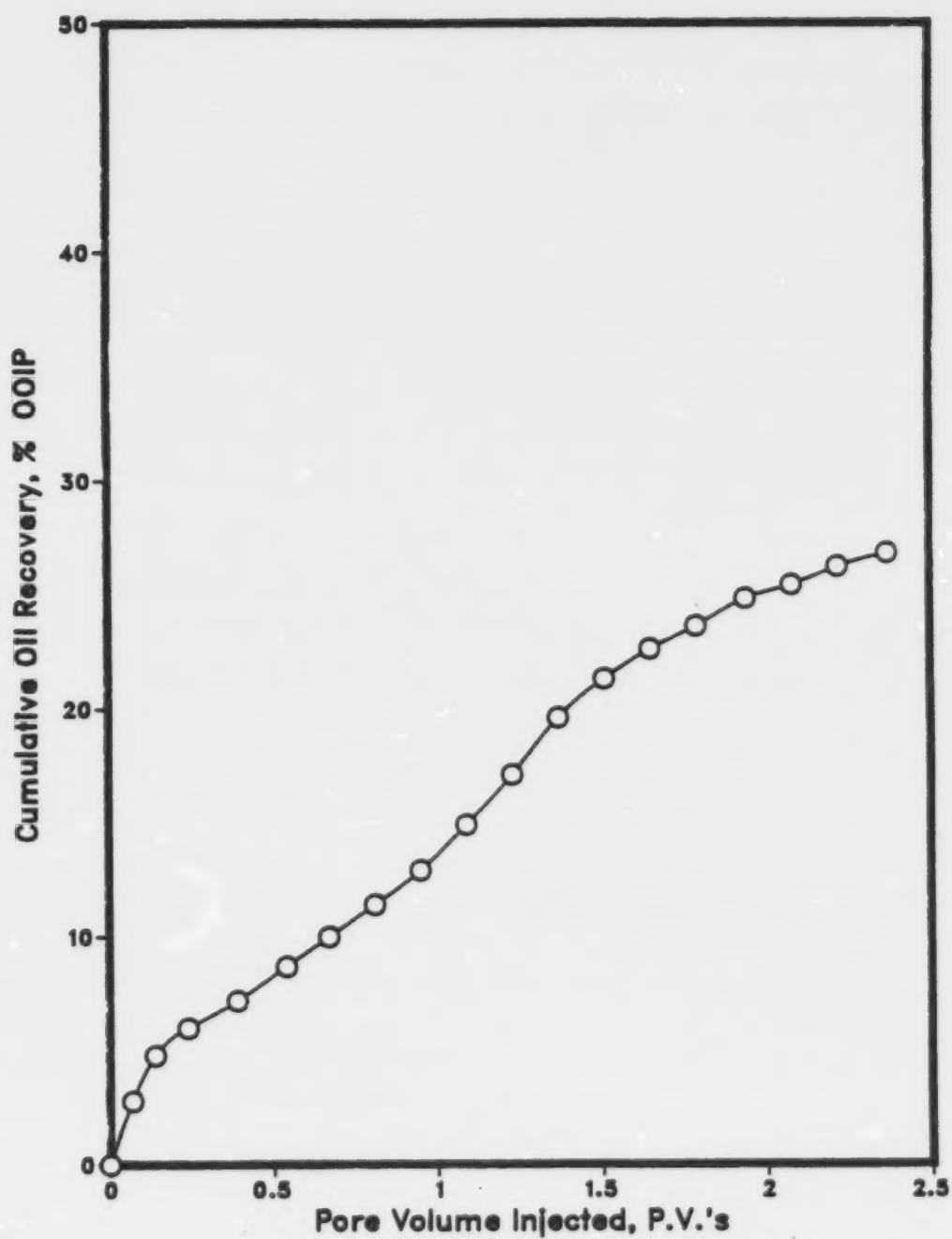


**Figure 5.67 :Run 55 Gas Injection Prior to Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

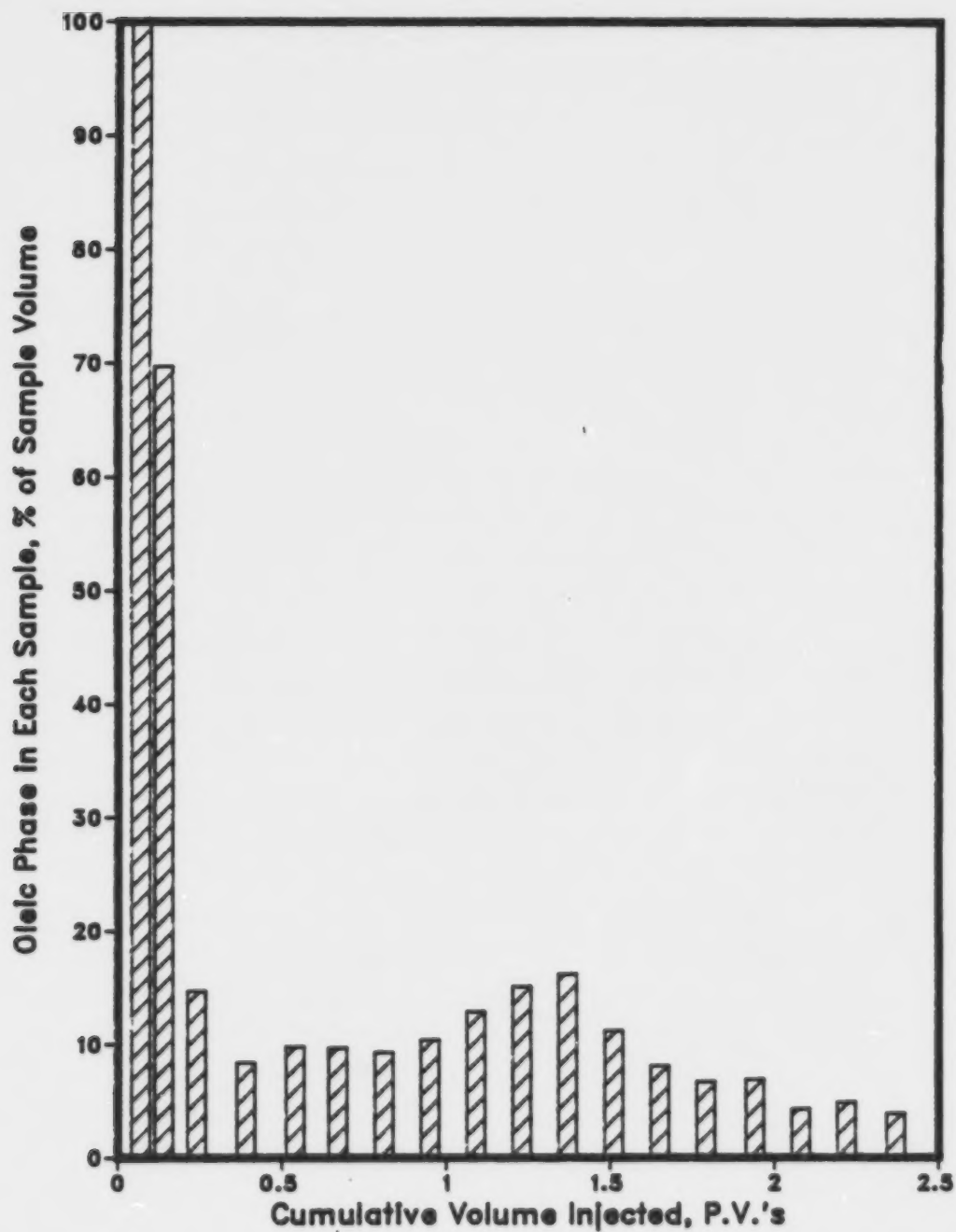


Figure 5.68 :Run 55 Gas Injection Prior to Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected

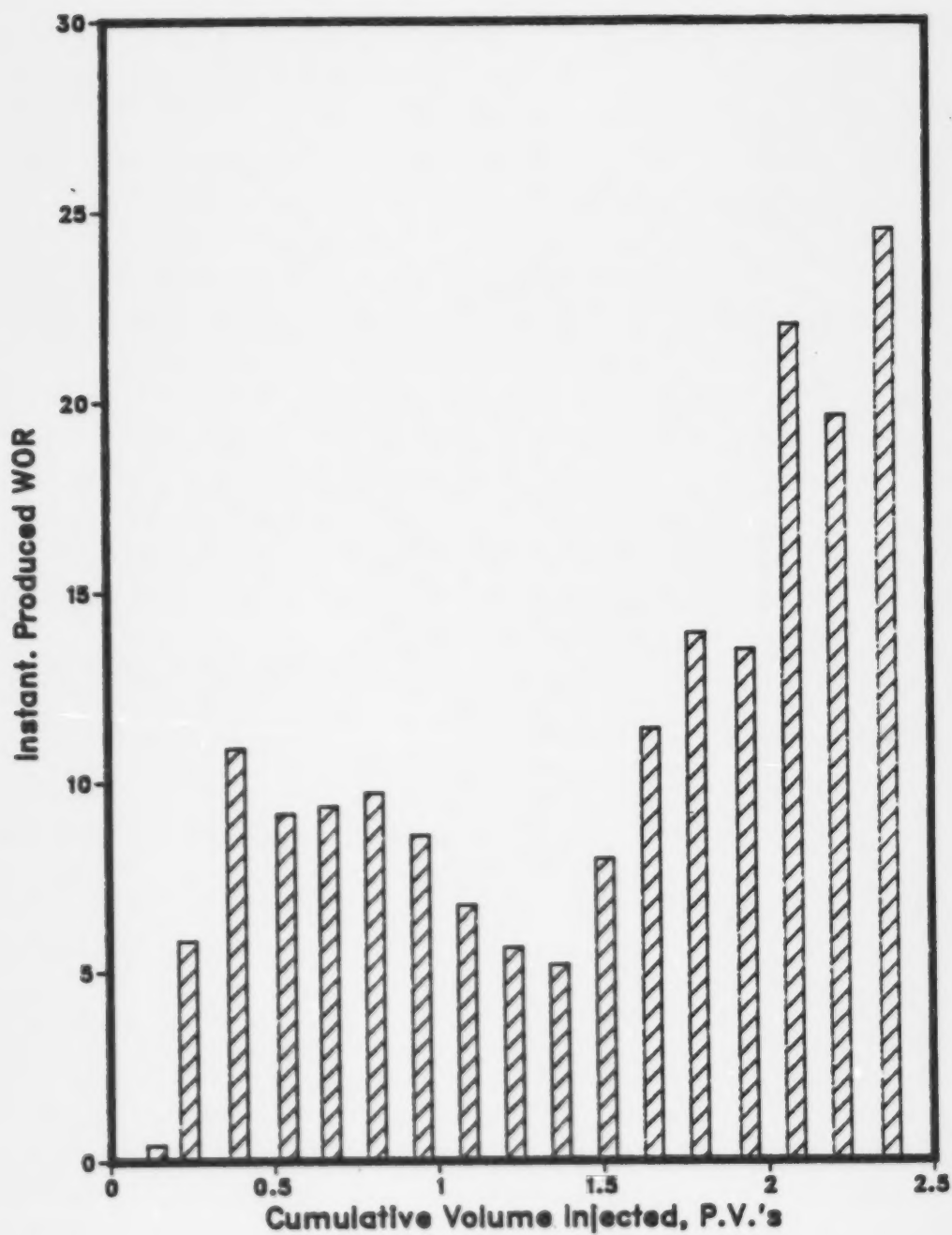


Figure 5.69: Run 55 Gas Injection Prior to Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

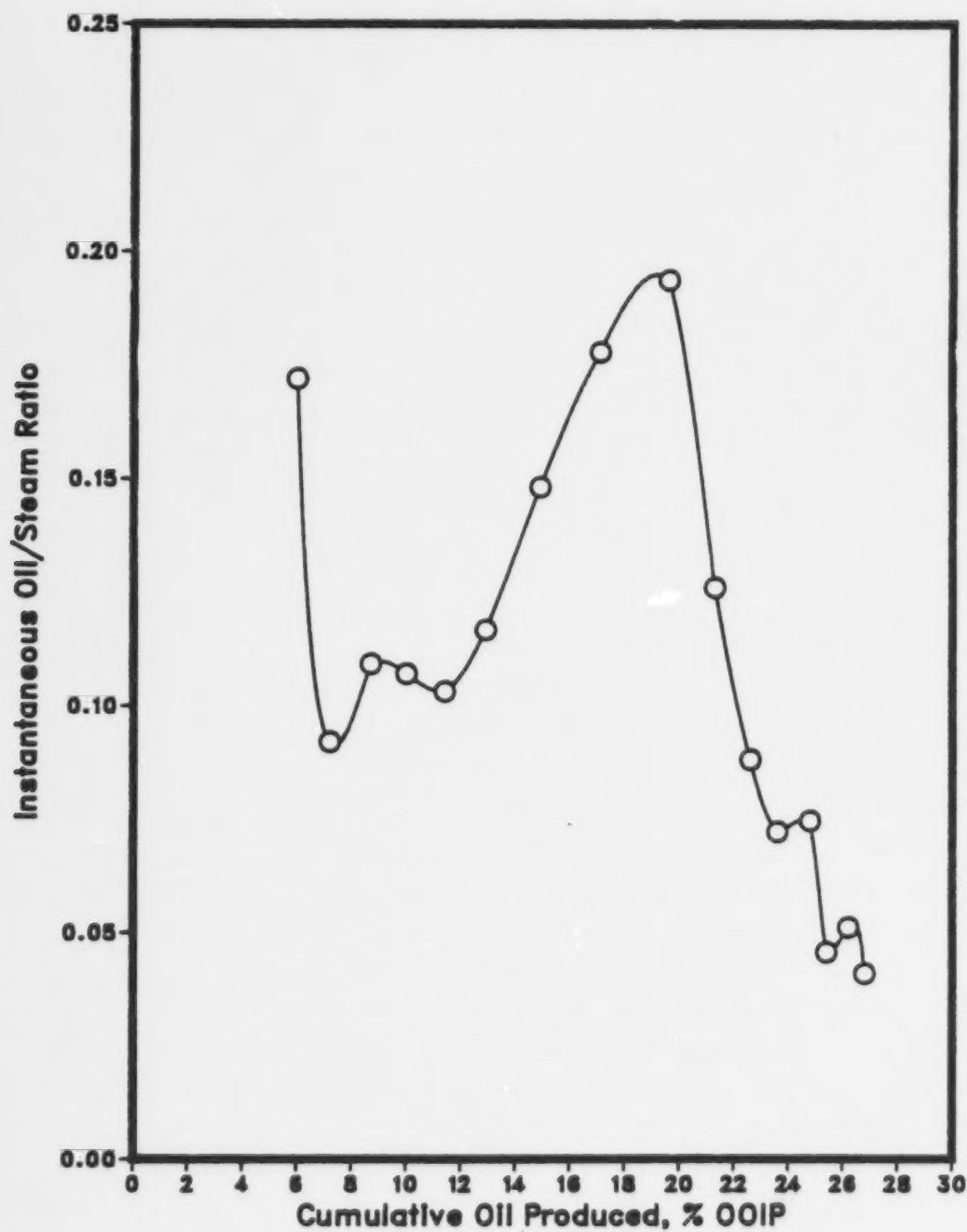


Table 5.18: Run 56 Gas Injection Prior to Solvent-Steamflood of Homogeneous Model

HC Pore Volume:	13120.0 cc	Type of Oil Used:	Faxam-100
Pore Volume:	14105.0 cc	Initial Model Temperature:	3.00 C
Bulk Volume:	42005.0 cc	Water Feed Flow Rate:	200.00 cc/min
Porosity:	33.6%	Boiler Feed Flow Rate:	29.20 cc/min
Initial Oil Satn.:	93.0%	Total Flow Rate of Steam:	229.20 cc/min
Initial H ₂ O Satn.:	6.3%	Solvent Flow Rate:	200.00 cc/min
Initial Gas Satn.:	0.6%	Gas Cap Volume:	90.0 cc
Solvent Vol. Inj.:	1400.0 cc	Steam Vol. Inj.:	32845.0 cc (2.33 PV)

Net Oil Recovery : 27.0% Solvent Recovery : 90.9% Final Oil Saturation : 67.9%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P. V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	(%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Solvent Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	66%	875	875	0.06	875	298	298	2.3%	577	41.2%	0.0000	0.00	100.0%
2	60%	1425	2300	0.16	700	578	578	4.4%	997	71.2%	0.0000	1.04	49.1%
3	53%	1475	3775	0.27	400	188	766	5.8%	1209	86.4%	0.3721	2.69	27.1%
4	10%	1920	5695	0.40	275	248	1014	7.7%	1236	88.3%	0.1672	5.98	14.3%
5	4%	2085	7780	0.55	580	557	1571	12.0%	1259	89.9%	0.3854	2.59	27.8%
6	2%	1885	9665	0.69	350	343	1914	14.6%	1266	90.4%	0.2280	4.39	18.6%
7	1%	2075	11740	0.83	295	292	2206	16.8%	1269	90.6%	0.1657	6.03	14.2%
8	1%	2105	13845	0.98	180	178	2384	18.2%	1271	90.8%	0.0935	10.69	8.6%
9	1%	2165	16010	1.14	150	149	2533	19.3%	1272	90.9%	0.0744	13.43	6.9%
10	0%	2000	18010	1.28	160	160	2693	20.5%	1272	90.9%	0.0870	11.50	8.0%
11	0%	2065	20075	1.42	145	145	2838	21.6%	1272	90.9%	0.0755	13.24	7.0%
12	0%	1860	21935	1.56	110	110	2948	22.5%	1272	90.9%	0.0629	15.91	5.9%
13	0%	2020	23955	1.70	140	140	3088	23.5%	1272	90.9%	0.0745	13.43	6.9%
14	0%	1920	25875	1.83	120	120	3208	24.5%	1272	90.9%	0.0667	15.00	6.3%
15	0%	2110	27985	1.98	95	95	3303	25.2%	1272	90.9%	0.0471	21.21	4.5%
16	0%	2065	30050	2.13	80	80	3383	25.8%	1272	90.9%	0.0403	24.81	3.9%
17	0%	2160	32210	2.28	90	90	3473	26.5%	1272	90.9%	0.0435	23.00	4.2%
18	0%	2035	34245	2.43	75	75	3548	27.0%	1272	90.9%	0.0383	26.13	3.7%

**Figure 5.70 :Run 56 Gas Injection Prior to Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected**

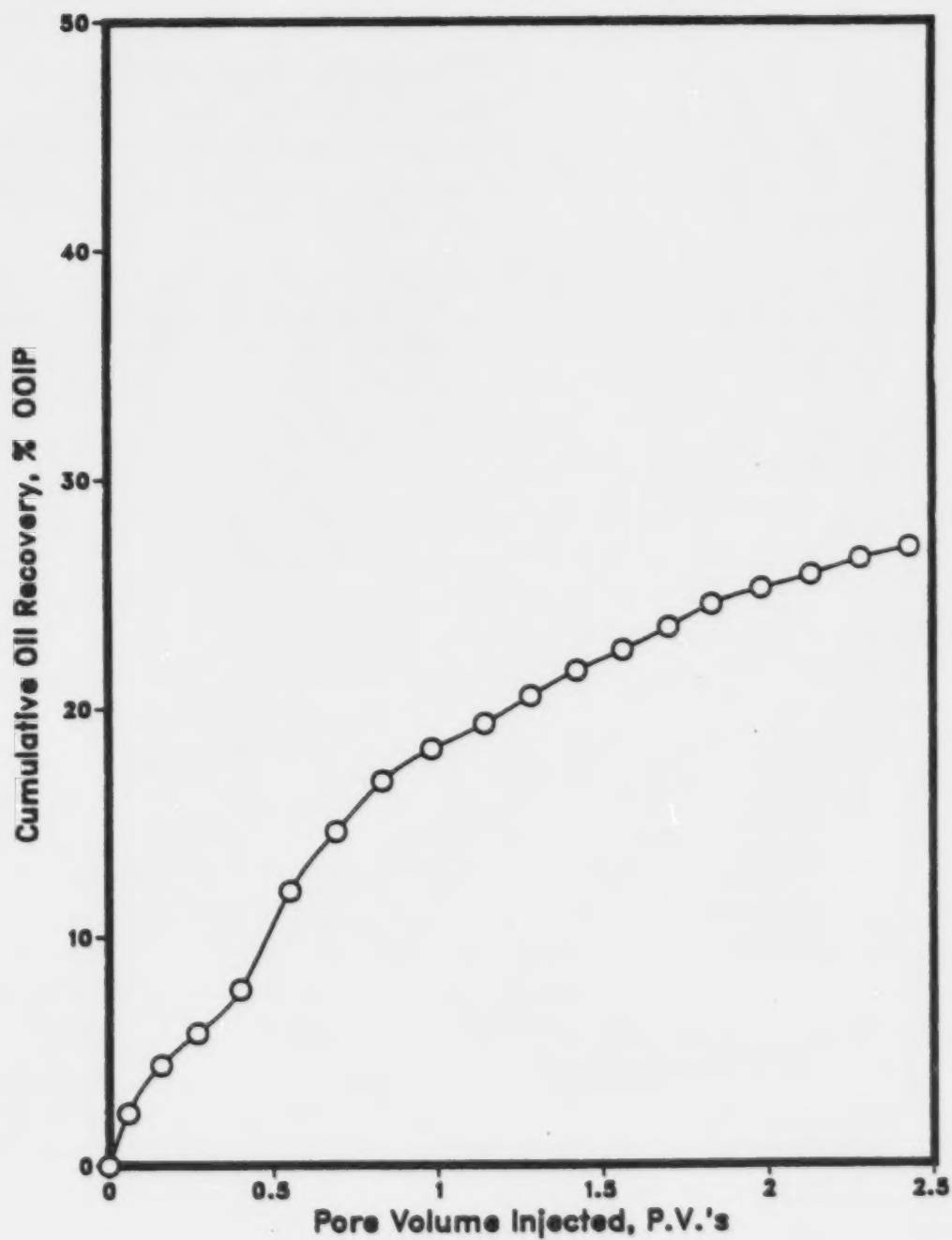


**Figure 5.71 :Run 56 Gas Injection Prior to Solvent-Steamflood
Oleic Phase in Each Sample Vs. Cumulative Volume Injected**

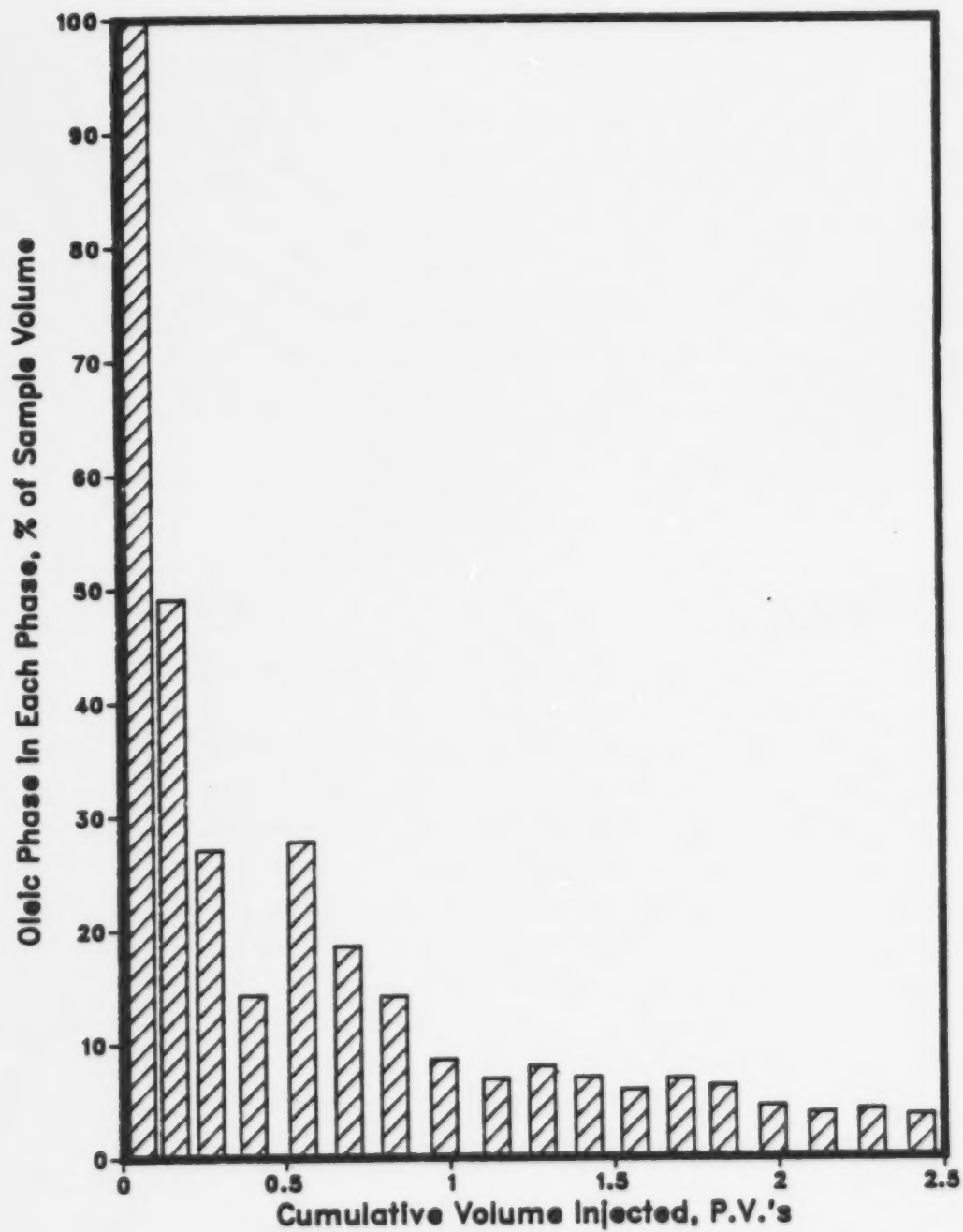


**Figure 5.72 :Run 56 Gas Injection Prior to Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

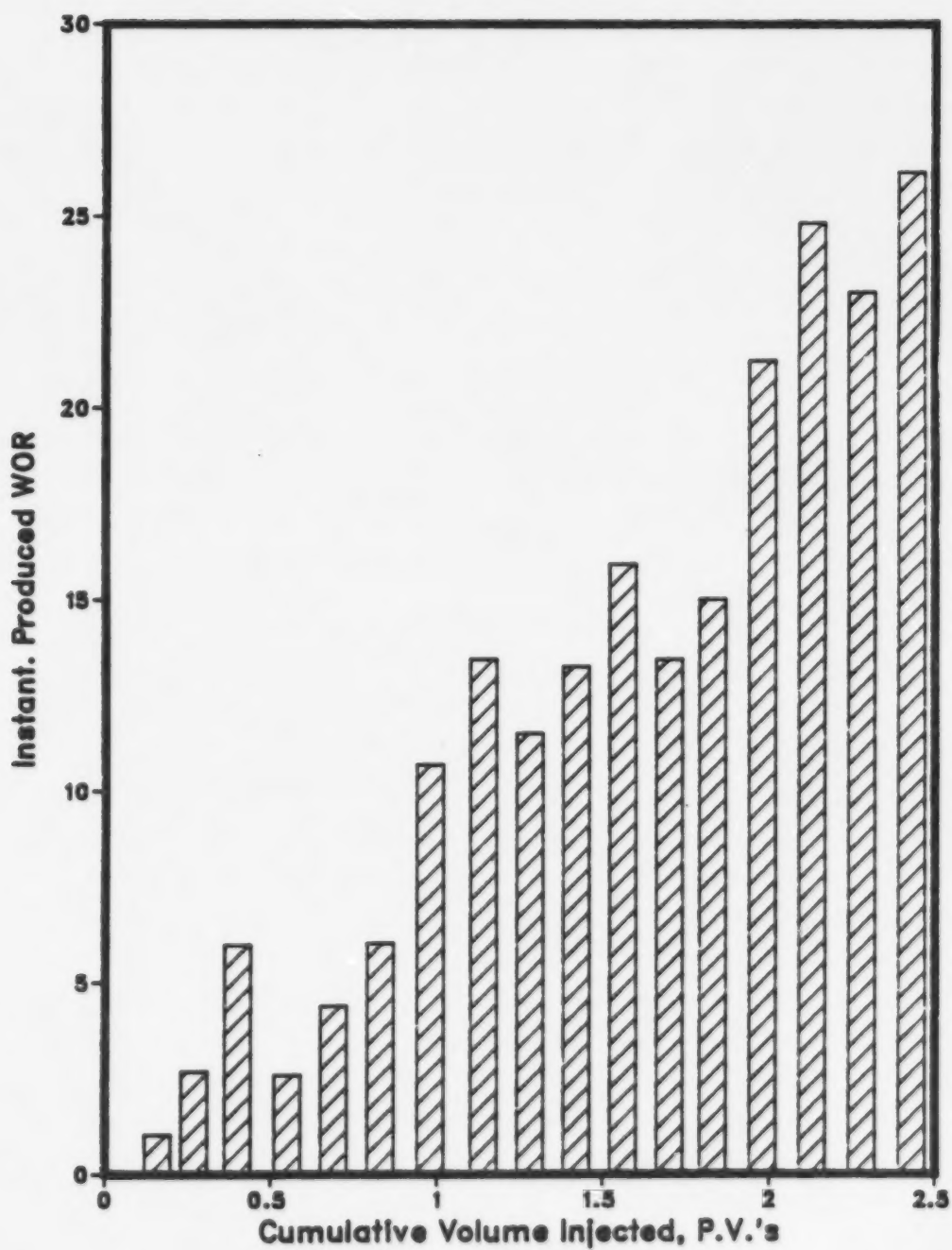


**Figure 5.73: Run 56 Gas Injection Prior to Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced**

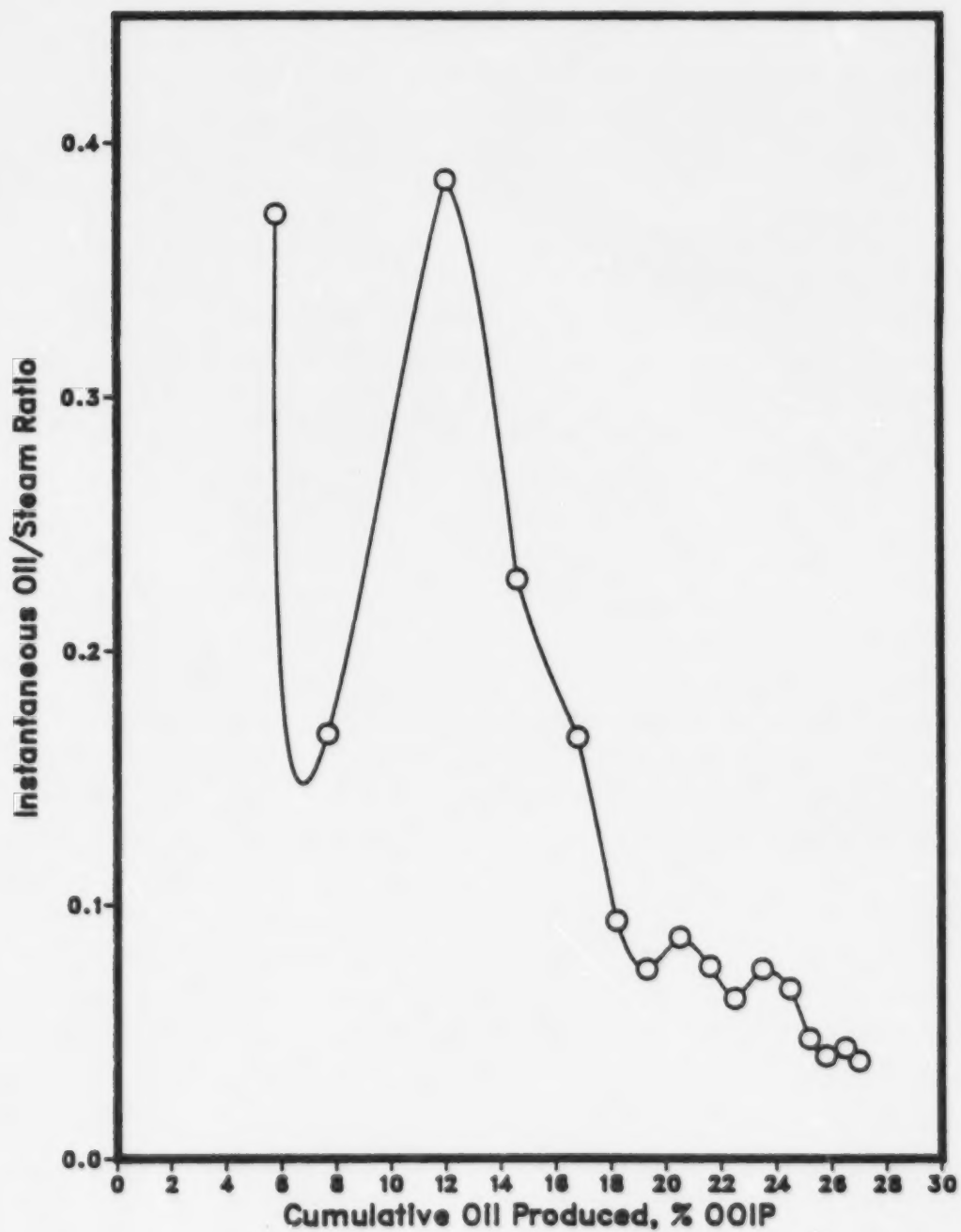
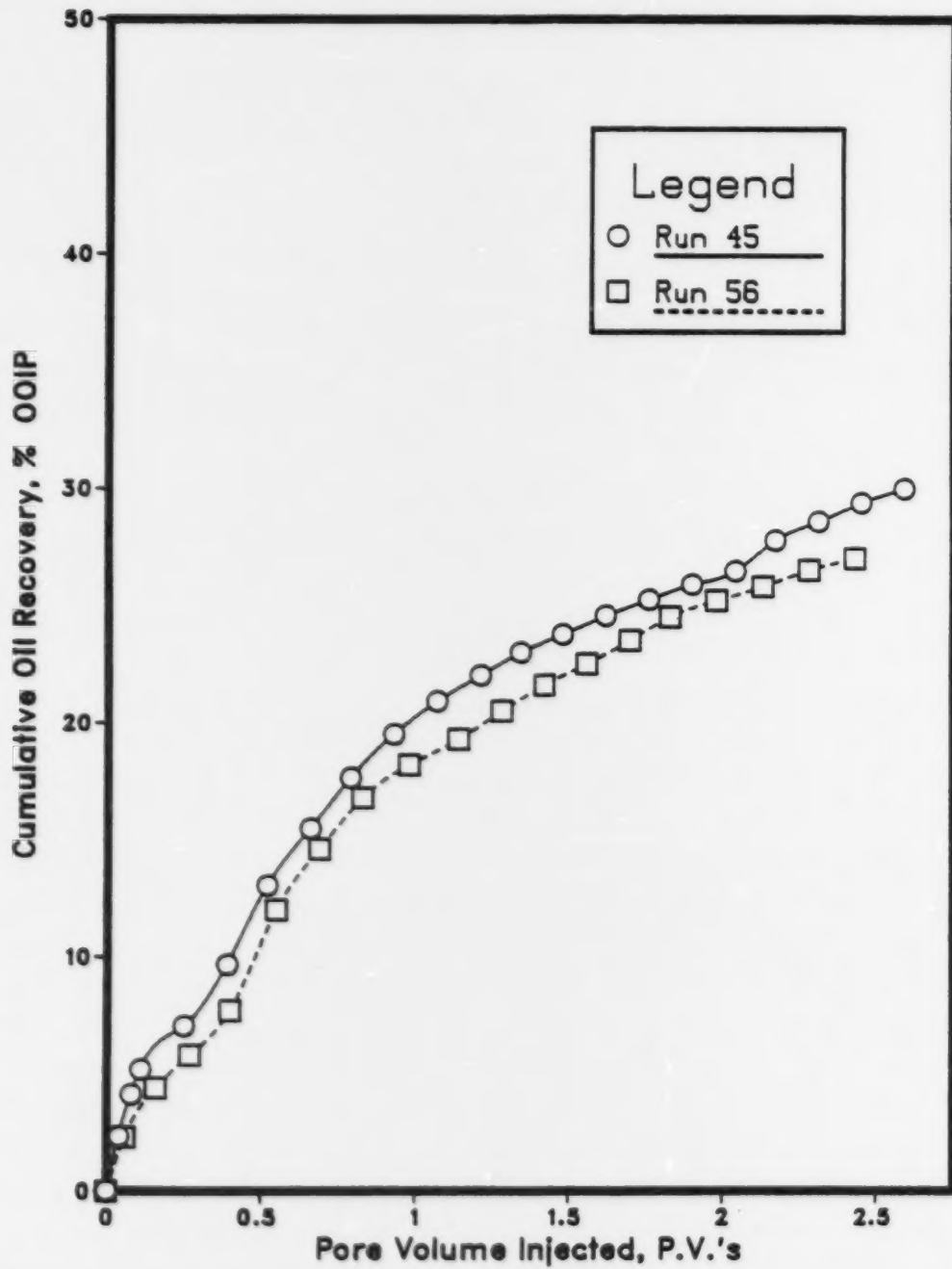


Figure 5.74: Comparison of Solvent-Steamflood Run 45 & Gas Injection Prior to Solvent-Steamflood Run 56 Recoveries Performed in a Homogeneous Model



injectivity is a problem, the injectivity improvement obtained by gas injection may justify the small decrease in oil recovery response.

Gas Injection Prior to Solvent and Steam Injection with Bottom Water

Runs 58, 59 and 62 involved performing a solvent-steamflood on a bottom water/gas cap reservoir. Results of each experiment are given in Tables 5.19, 5.20 and 5.21, respectively. These experiments were similar to Runs 49, 50, 51, 53 and 54 except that Runs 58, 59 and 62 incorporated a gas cap in the low pressure model. The bottom water thicknesses for Runs 58, 59 and 62 were 9.8%, 13.6% and 12.0% of the gross model thickness, respectively, and the initial gas saturations were 0.6% (Run 58), 0.6% (Run 59) and 0.3% (Run 62).

The recovery curves for Runs 58 (Figure 5.75), 59 (Figure 5.79) and 62 (Figure 5.83) all indicated that the presence of bottom water and a gas cap affected the total oil recovery yielded by the solvent-steamflood process. The recovery curve for Run 58 (Figure 5.75) showed a relatively lower oil recovery (18.2%) than was obtained in Runs 59 (24.7%) and 62 (20.0%). The lower recovery may have been due to the slightly larger gas cap of Run 58 which caused the solvent and steam to be further diverted away from both the bottom water and oil zone. This resulted in less solvent and steam penetrating the oil region and therefore less oil was mobilized and subsequently recovered. Therefore the gas saturation should be optimized to increase oil recovery. Figure 5.79 illustrates that Run 59 had the highest overall oil recovery (24.7%) of the three experiments. Run 59 had a slightly smaller gas cap than Run 58 which may have caused more steam to penetrate the oil zone resulting in a better oil recovery. The recovery curve for Run 62 (Figure 5.83) indicates that Run 62 also had a higher recovery (20.0%) than Run 58. As mentioned before this higher recovery was probably caused by the slightly smaller gas cap contained in Run 62, and therefore a greater invasion of the oil zone by the injected solvent and steam resulted.

The bar plots of volume as a percentage of oleic phase in each sample collected injected and instantaneous produced WOR versus cumulative volume injected for Runs 58 (Fig. 5.76 & 5.77), 59 (Fig. 5.80 & 5.81) and 62 (Fig. 5.84 & 5.85) suggest that the introduction of a "gas cap" in the model was a dominating factor in the overall recovery for all the experiments. Observation of all of these plots indicates that breakthrough during the experiments occurred very early. Early breakthrough was caused by the very unstable displacement of oil by the solvent and steam. The lack of stability was a result of the presence of bottom water and gas cap which enabled the injected solvent and steam to flow above and below the oil layer. Once breakthrough had occurred, the instantaneous hydrocarbon produced for Figures 5.76, 5.80 and 5.84 dropped to relatively small values. Comparison of Figures 5.76, 5.80 and 5.84 with the corresponding plots of Runs 49, 50, 51, 53 and 54 (solvent-steamflood in a bottom water model) indicates that breakthrough occurred sooner in experiments 58, 59 and 62 which suggests that the gas cap was detrimental to the stability of the displacement. In these three runs, the solvent and steam were diverted away from the oil to a greater extent by the bottom water and gas cap than in the case of only bottom water.

The plots of instantaneous oil/steam ratio versus cumulative oil produced are displayed in Figures 5.78 (Run 58), 5.82 (Run 59) and 5.86 (Run 62). Overall the oil/steam ratios were slightly higher for Runs 58, 59 and 62 as compared to Runs 49, 50, 51, 53 and 54 which were experiments involving the solvent-steamflood of a bottom water model.

Examination of the temperature profiles for Runs 58 (Fig. A.203-A.210), 59 (Fig. A.215-A.222) and 62 (Fig. A.227-A.234) reveals that the presence of a gas cap allowed the heat to advance through the upper and lower portions of the model at about the same rate. The advancement of the heat through the lower region was only slightly faster due to some of the steam underriding the oil and gas cap into the bottom water. Of the three experiments the heat advanced fastest through the bottom portion of the model in Run 59

Table 5.19 : Run 58 Gas Injection Prior to Solvent-Steamflood of Bottom Water Model

HC Pore Volume : 12920.0 cc		Type of Oil Used : Faxam-100										
Pore Volume : 14955.0 cc		Initial Model Temperature 3.00 C										
Bulk Volume : 42005.0 cc		Water Feed Flow Rate : 200.00 cc/min										
Porosity : 35.6%		Boiler Feed Flow Rate : 29.20 cc/min										
Initial Oil Satn. : 86.4%		Total Flow Rate of Steam 229.20 cc/min										
Initial H2O Satn. : 13.0%		Solvent Flow Rate : 200.00 cc/min										
Initial Gas Satn. : 0.6%		Gas Cap Volume : 90.0 cc										
Solvent Vol. Inj. : 1400.0 cc		Steam Vol. Inj. : 32515.0 cc (2.17 PV)										
		Bottom Water Layer Thickness : 9.8% (% Gross Thickness)										
Net Oil Recovery : 18.2%		Final Oil Saturation : 70.7%										
		Solvent Recovery : 88.7%										
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)	(cc)	(%)	Oil-Steam Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample
1	61%	875	875	0.06	465	181	1.4%	284	20.3%	0.0000	0.88	53.1%
2	74%	1195	2070	0.14	985	256	3.4%	1013	72.4%	0.0000	0.21	82.4%
3	54%	1340	3410	0.23	230	106	4.2%	1137	81.2%	0.2072	4.83	17.2%
4	28%	1855	5265	0.35	195	140	5.3%	1192	85.1%	0.1175	8.51	10.5%
5	17%	2015	7280	0.49	100	83	5.9%	1209	86.4%	0.0522	19.15	5.0%
6	13%	1940	9220	0.62	70	61	6.4%	1218	87.0%	0.0374	26.71	3.6%
7	5%	2065	11285	0.75	180	171	7.7%	1227	87.6%	0.0955	10.47	8.7%
8	4%	1975	13260	0.89	145	139	8.8%	1233	88.1%	0.0792	12.62	7.3%
9	3%	2185	15445	1.03	135	131	9.8%	1237	88.4%	0.0659	15.19	6.2%
10	2%	1915	17360	1.16	135	132	10.8%	1240	88.6%	0.0758	13.19	7.0%
11	1%	2055	19415	1.30	190	188	12.3%	1242	88.7%	0.1019	9.82	9.2%
12	0%	2035	21450	1.43	160	160	13.5%	1242	88.7%	0.0853	11.72	7.9%
13	0%	2125	23575	1.58	140	140	14.6%	1242	88.7%	0.0705	14.18	6.6%
14	0%	2075	25650	1.72	105	105	15.4%	1242	88.7%	0.0533	18.76	5.1%
15	0%	2200	27850	1.86	75	75	16.0%	1242	88.7%	0.0353	28.33	3.4%
16	0%	1945	29795	1.99	90	90	16.7%	1242	88.7%	0.0485	20.61	4.6%
17	0%	2140	31935	2.14	115	115	17.6%	1242	88.7%	0.0568	17.61	5.4%
18	0%	1980	33915	2.27	80	80	18.2%	1242	88.7%	0.0421	23.75	4.0%

Figure 5.75 :Run 58 Gas Injection Prior to Solv
Cumulative Oil Recovery Vs. Pore Volume

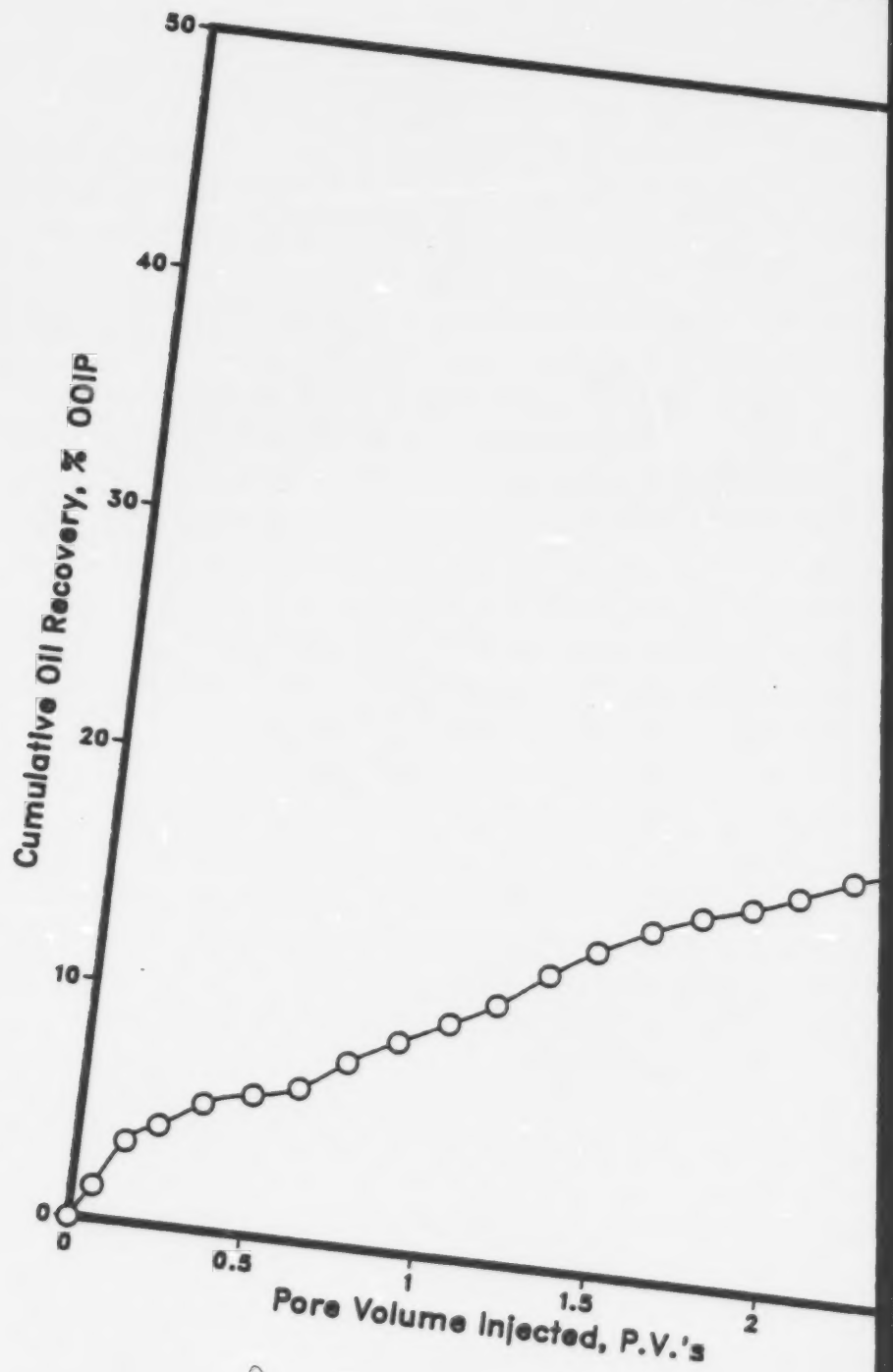


**Figure 5.76 :Run 58 Gas Injection Prior to Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

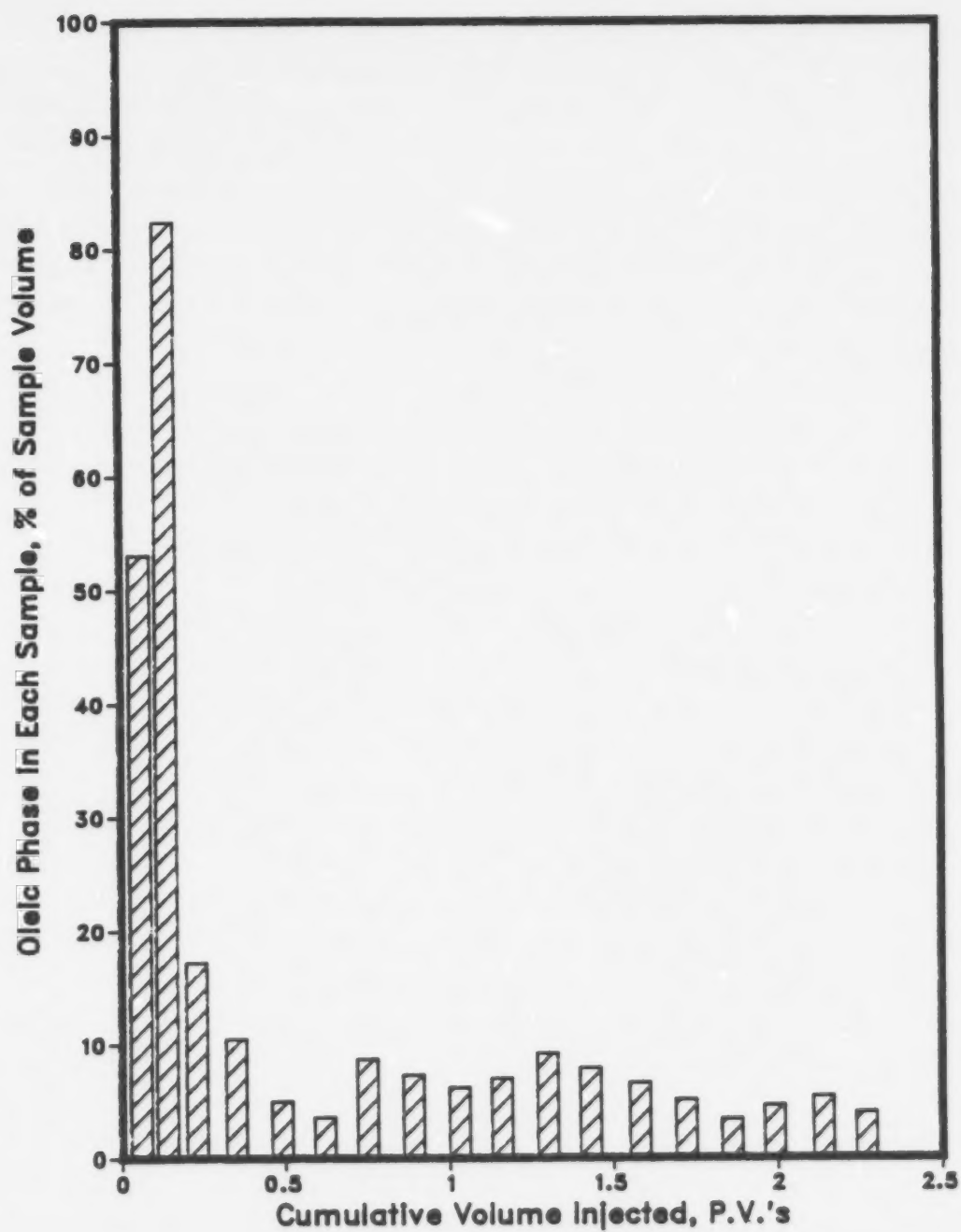


**Figure 5.77 :Run 58 Gas Injection Prior to Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

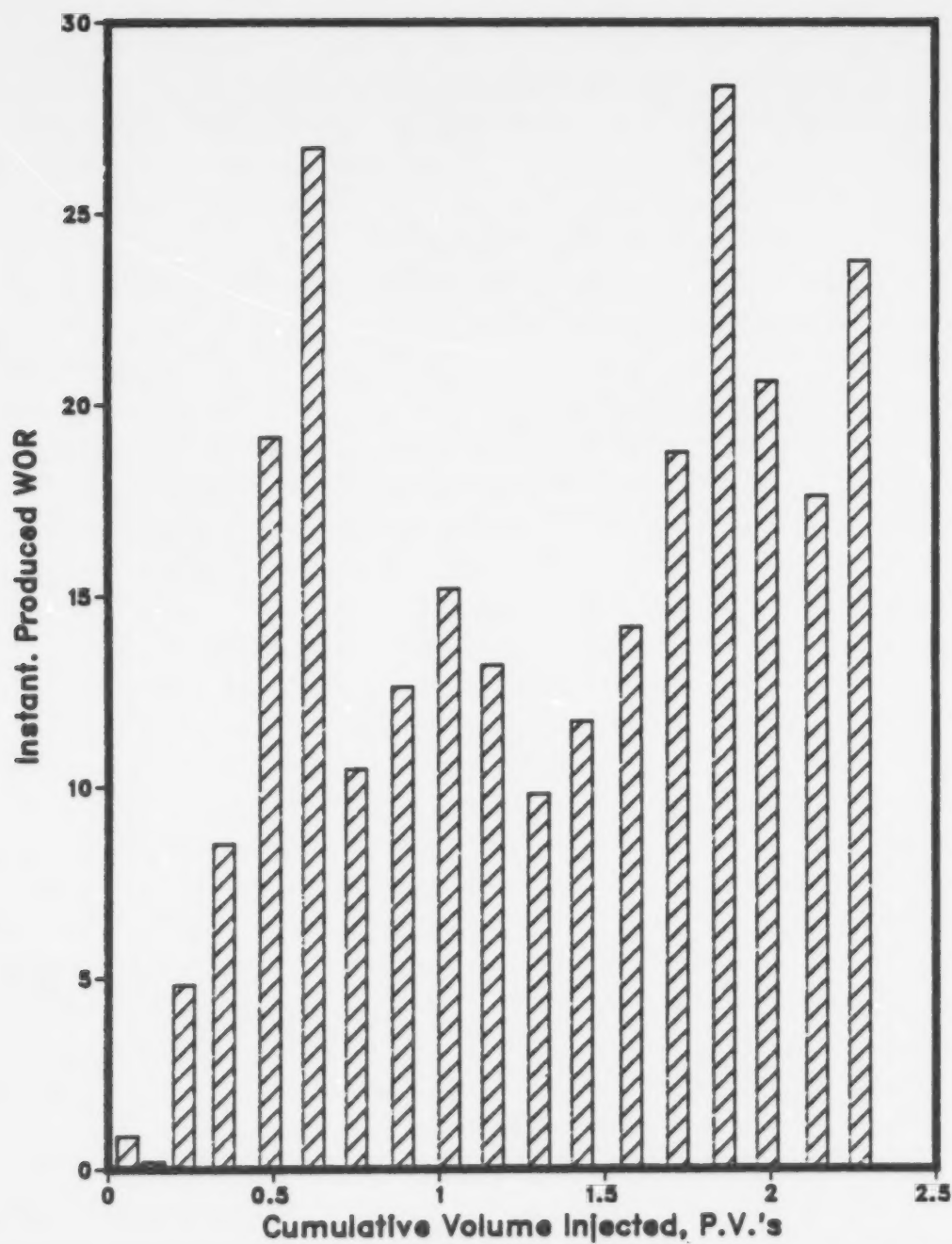


**Figure 5.78 :Run 58 Gas Injection Prior to Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced**

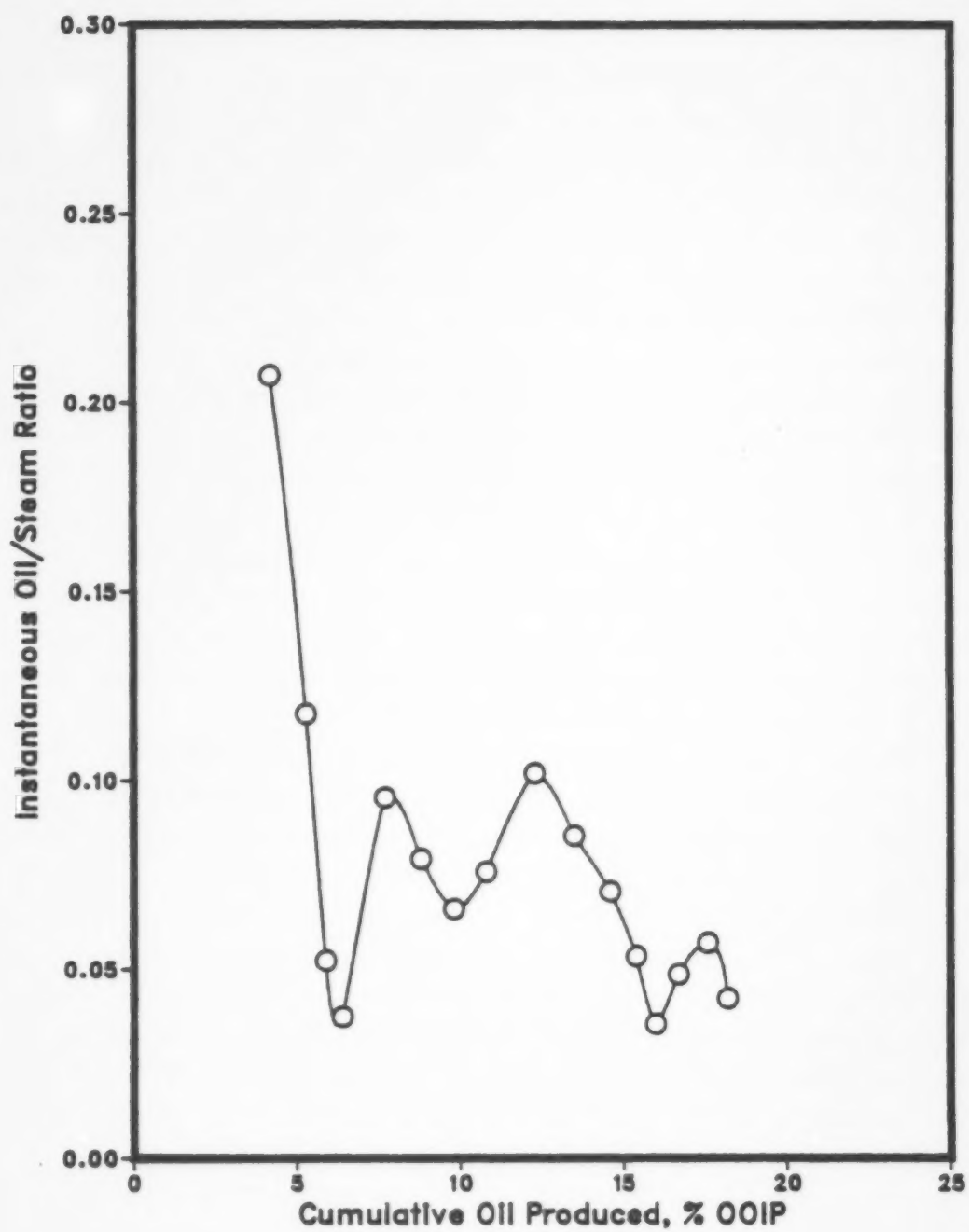


Table 5.20 : Run 59 Gas Injection Prior to Solvent-Steamflood of Bottom Water Model

HC Pore Volume : 12805.0 cc
 Pore Volume : 15005.0 cc
 Bulk Volume : 42005.0 cc
 Porosity : 35.7%
 Initial Oil Satn. : 85.3%
 Initial H₂O Satn. : 14.1%
 Initial Gas Satn. : 0.6%
 Solvent Vol. Inj. : 1400.0 cc

Type of Oil Used : Faxam-100
 Initial Model Temperature : 3.00 C
 Water Feed Flow Rate : 200.00 cc/min
 Boiler Feed Flow Rate : 29.20 cc/min
 Total Flow Rate of Steam : 229.20 cc/min
 Solvent Flow Rate : 200.00 cc/min
 Gas Cap Volume : 85.0 cc
 Steam Vol. Inj. : 33070.0 cc (2.20 PV)
 Bottom Water Layer Thickness : 13.6% (% Gross Thickness)

Net Oil Recovery : 24.7%

Solvent Recovery : 96.5%

Final Oil Saturation : 64.2%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)		HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)		Cum. Sol. Rec. (%)	Oil-Steam Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample
			(cc)	(P.V.)			(cc)	(%)				
1	68%	1375	1375	0.09	1305	418	418	3.3%	63.4%	0.0000	0.05	94.9%
2	62%	1425	2800	0.19	575	219	637	5.0%	88.8%	0.0000	1.48	40.4%
3	16%	1580	4380	0.29	390	328	965	7.5%	93.2%	0.3277	3.05	24.7%
4	7%	2040	6420	0.43	205	191	1156	9.0%	94.2%	0.1117	8.95	10.0%
5	5%	1860	8280	0.55	180	171	1327	10.4%	94.9%	0.1071	9.33	9.7%
6	3%	2015	10295	0.69	190	184	1511	11.8%	95.3%	0.1041	9.61	9.4%
7	3%	1930	12225	0.81	175	170	1681	13.1%	95.6%	0.0997	10.03	9.1%
8	2%	2020	14245	0.95	180	176	1857	14.5%	95.9%	0.0978	10.22	8.9%
9	2%	1950	16195	1.08	170	167	2024	15.8%	96.1%	0.0955	10.47	8.7%
10	2%	2055	18250	1.22	155	152	2176	17.0%	96.4%	0.0816	12.26	7.5%
11	1%	2010	20260	1.35	135	134	2310	18.0%	96.4%	0.0720	13.89	6.7%
12	1%	2020	22280	1.48	135	134	2444	19.1%	96.5%	0.0716	13.96	6.7%
13	0%	1970	24250	1.62	130	130	2574	20.1%	96.5%	0.0707	14.15	6.6%
14	0%	2145	26395	1.76	130	130	2704	21.1%	96.5%	0.0645	15.50	6.1%
15	0%	1970	28365	1.89	110	110	2814	22.0%	96.5%	0.0591	16.91	5.6%
16	0%	2035	30400	2.03	130	130	2944	23.0%	96.5%	0.0682	14.65	6.4%
17	0%	1950	32350	2.16	120	120	3064	23.9%	96.5%	0.0656	15.25	6.2%
18	0%	2120	34470	2.30	105	105	3169	24.7%	96.5%	0.0521	19.19	5.0%

Figure 5.79 :Run 59 Gas Injection Prior to Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

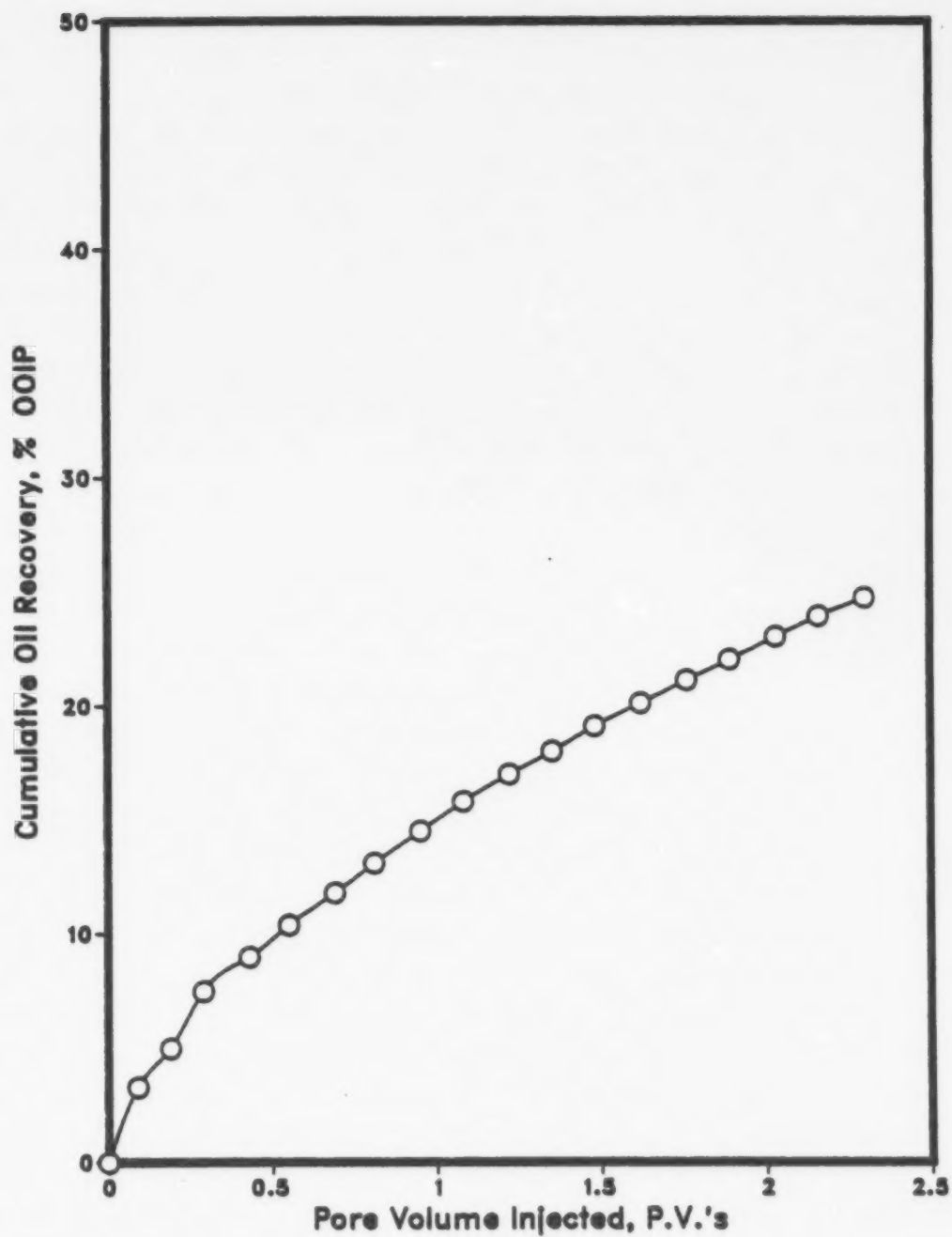


Figure 5.80: Run 59 Gas Injection Prior to Solvent-Steamflood
Oleic Phase in Each Sample Vs. Cumulative Volume Injected

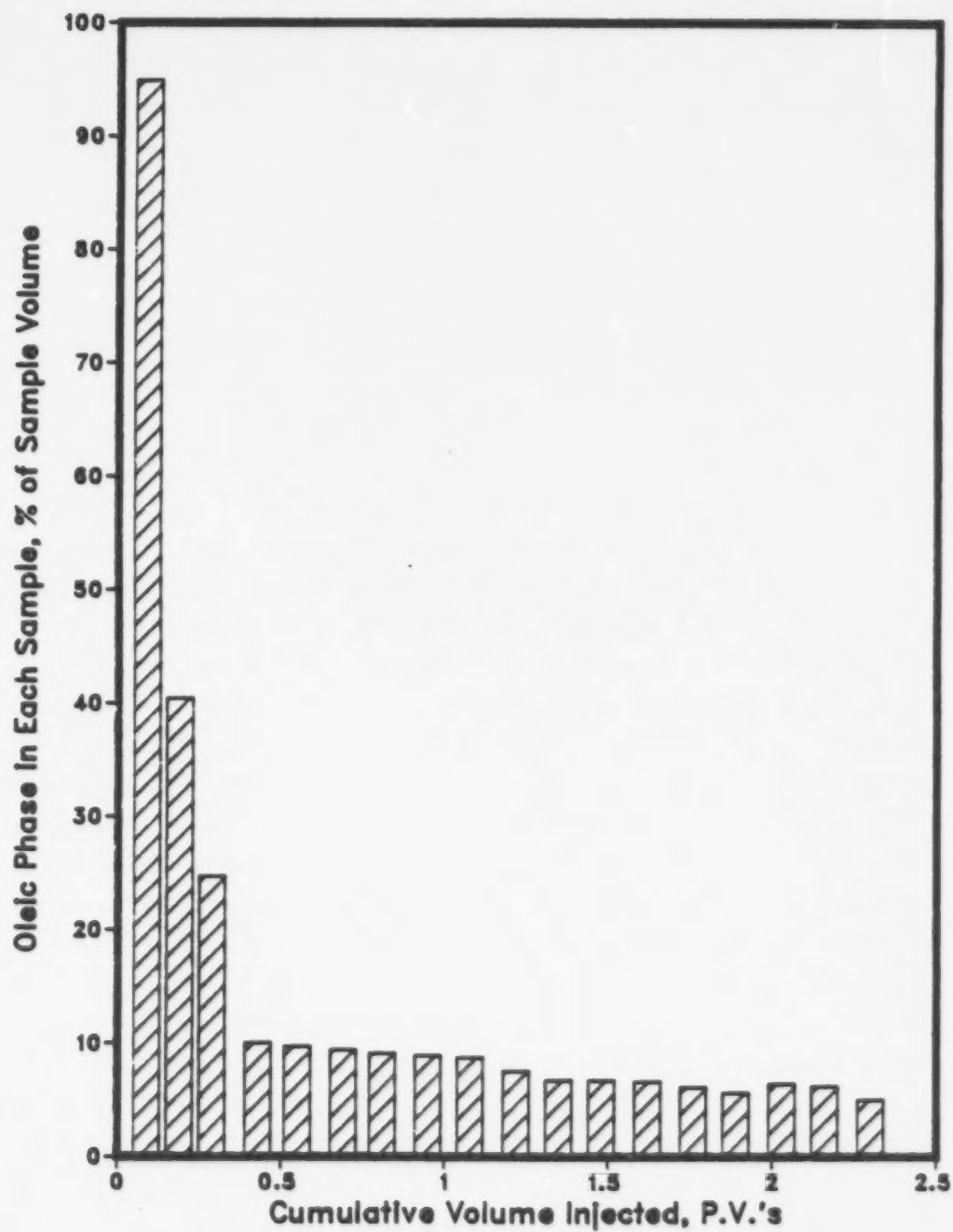


**Figure 5.81 :Run 59 Gas Injection Prior to Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

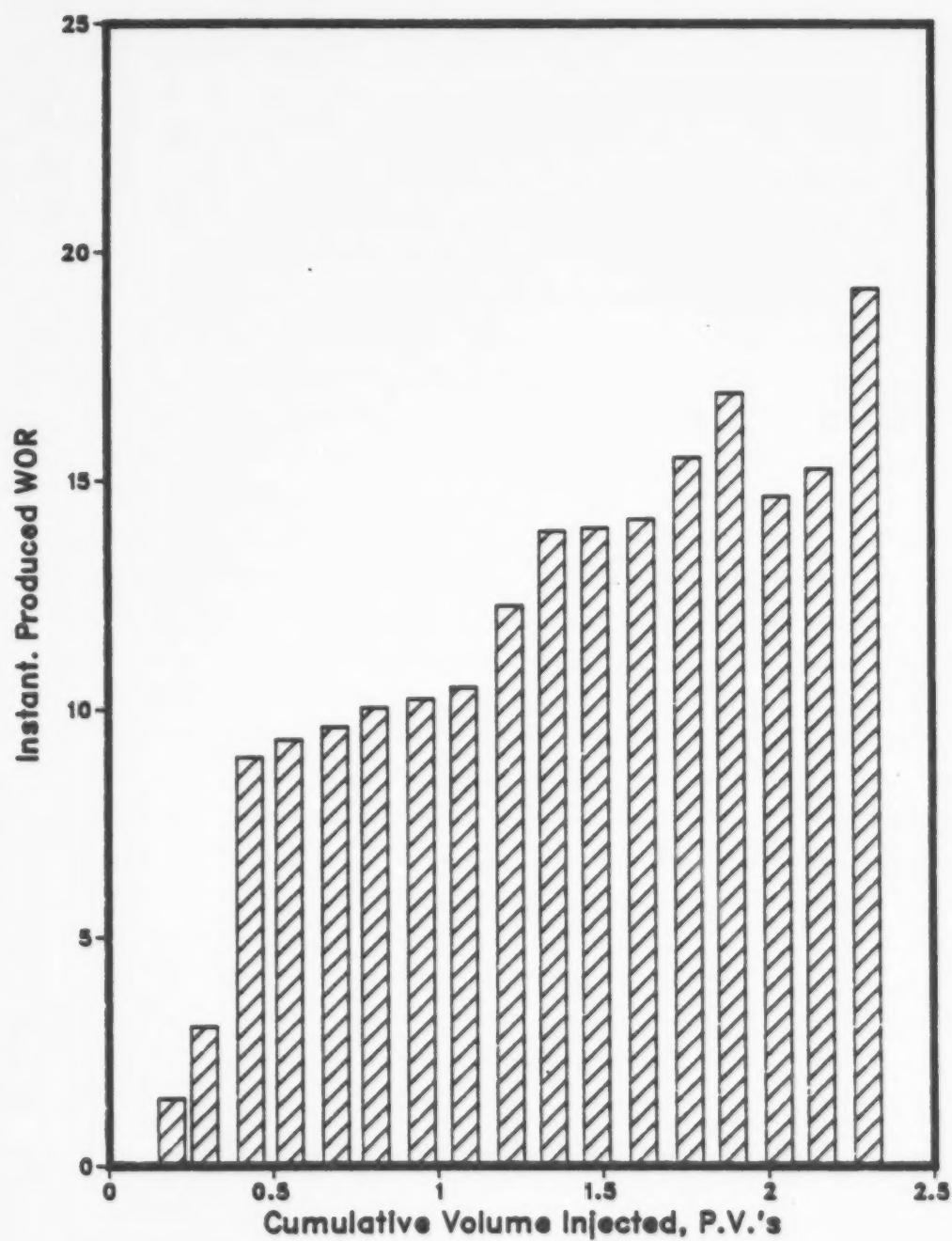


Figure 5.82 :Run 59 Gas Injection Prior to Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

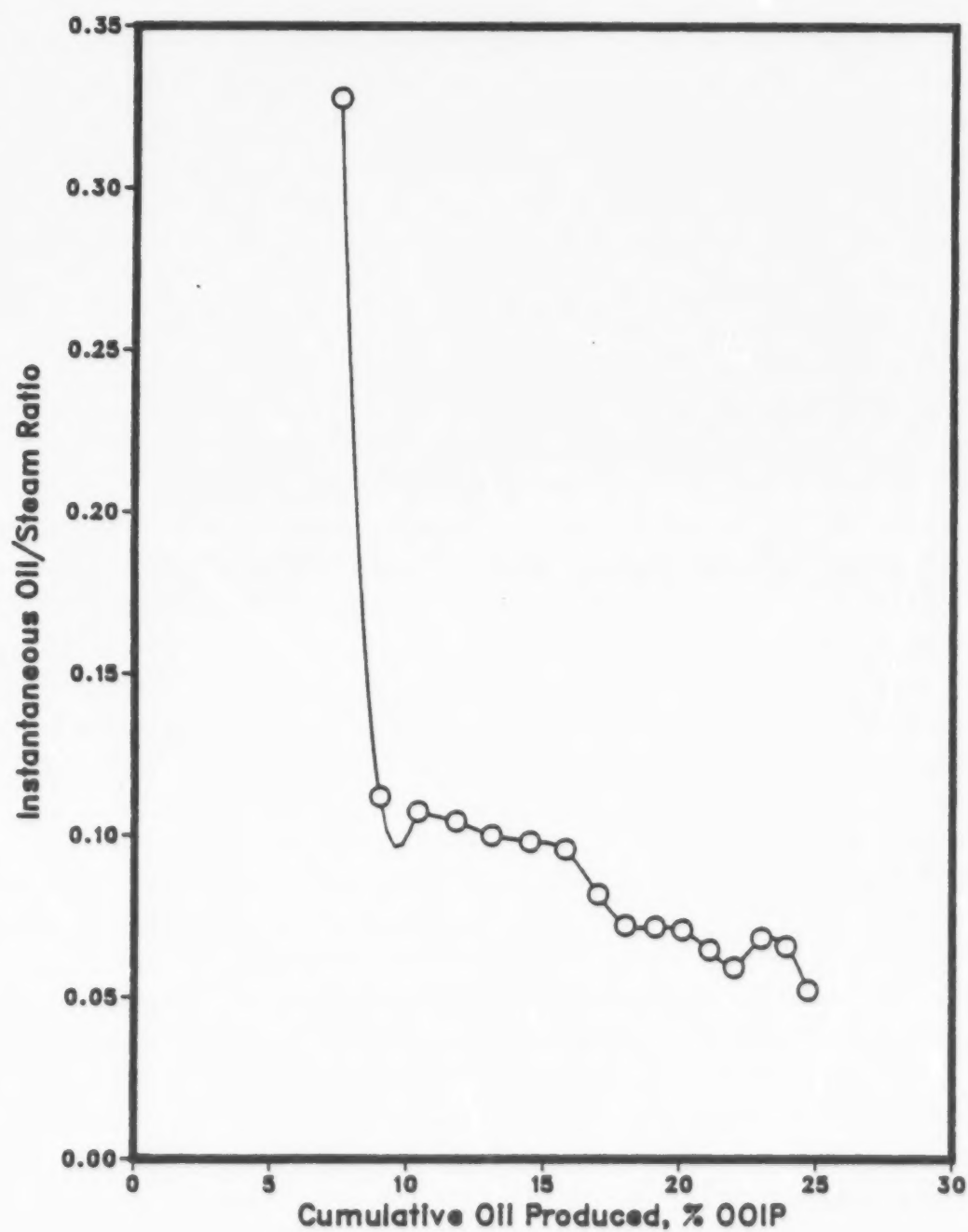


Table 5.21: Run 62 Gas Injection Prior to Solvent-Steamflood of Bottom Water Model

HC Pore Volume		12730.0 cc	Type of Oil Used :		Faxam-100								
Pore Volume :		15260.0 cc	Initial Model Temperature		3.00 C								
Bulk Volume :		42005.0 cc	Water Feed Flow Rate :		200.00 cc/min								
Porosity :		36.3%	Boiler Feed Flow Rate :		29.20 cc/min								
Initial Oil Satn. :		83.4%	Total Flow Rate of Steam		229.20 cc/min								
Initial H2O Satn. :		16.3%	Solvent Flow Rate :		200.00 cc/min								
Initial Gas Satn. :		0.3%	Gas Cap Volume :		45.0 cc								
Solvent Vol. Inj. :		1400.0 cc	Steam Vol. Inj. :		33595.0 cc (2.19 PV)								
			Bottom Water Layer Thickness :		12.0% (% Gross Thickness)								
Net Oil Recovery : 20.0 %			Solvent Recovery : 94.7 %										
			Final Oil Saturation : 66.7 %										
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	(%OOIP)	Cum. Sol. Rec. (cc)	(%)	Oil-Steam Ratio	Inst. Prod. WOR	Inst. HC Prod. % of Sample
1	66%	1025	1025	0.07	760	258	258	2.0%	502	35.9%	0.0000	0.35	74.1%
2	64%	1800	2825	0.19	940	338	596	4.7%	1104	78.9%	0.0000	0.91	52.2%
3	24%	1905	4730	0.31	435	331	927	7.3%	1208	86.3%	0.2959	3.38	22.8%
4	12%	2000	6730	0.44	140	123	1050	8.2%	1225	87.5%	0.0753	13.29	7.0%
5	22%	2130	8860	0.58	195	152	1202	9.4%	1268	90.6%	0.1008	9.92	9.2%
6	21%	1900	10760	0.71	140	111	1313	10.3%	1297	92.6%	0.0795	12.57	7.4%
7	6%	2015	12775	0.84	250	235	1548	12.2%	1312	93.7%	0.1416	7.06	12.4%
8	4%	1990	14765	0.97	155	149	1697	13.3%	1318	94.1%	0.0845	11.84	7.8%
9	2%	2040	16805	1.10	145	142	1839	14.4%	1321	94.4%	0.0765	13.07	7.1%
10	2%	1900	18705	1.23	120	118	1957	15.4%	1323	94.5%	0.0674	14.83	6.3%
11	1%	2085	20790	1.36	125	124	2081	16.3%	1324	94.6%	0.0638	15.68	6.0%
12	1%	2040	22830	1.50	155	153	2234	17.5%	1326	94.7%	0.0822	12.16	7.6%
13	0%	2290	25120	1.65	50	50	2284	17.9%	1326	94.7%	0.0223	44.80	2.2%
14	0%	1920	27040	1.77	60	60	2344	18.4%	1326	94.7%	0.0323	31.00	3.1%
15	0%	2035	29075	1.91	55	55	2399	18.8%	1326	94.7%	0.0278	36.00	2.7%
16	0%	1865	30940	2.03	60	60	2459	19.3%	1326	94.7%	0.0332	30.08	3.2%
17	0%	2040	32980	2.16	35	35	2494	19.6%	1326	94.7%	0.0175	57.29	1.7%
18	0%	2015	34995	2.29	55	55	2549	20.0%	1326	94.7%	0.0281	35.64	2.7%

Figure 5.83 :Run 62 Gas Injection Prior to Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

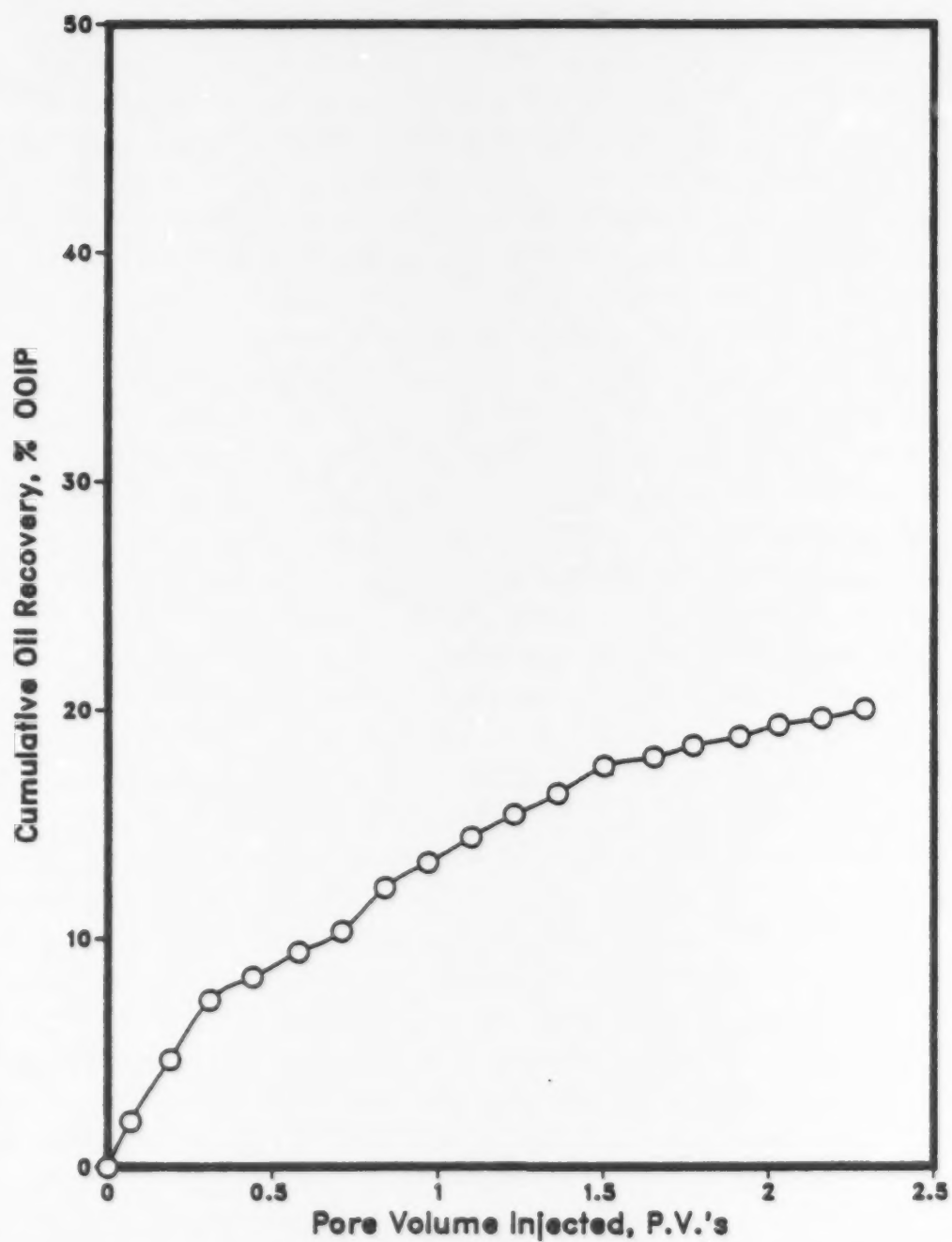


**Figure 5.84 :Run 62 Gas Injection Prior to Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

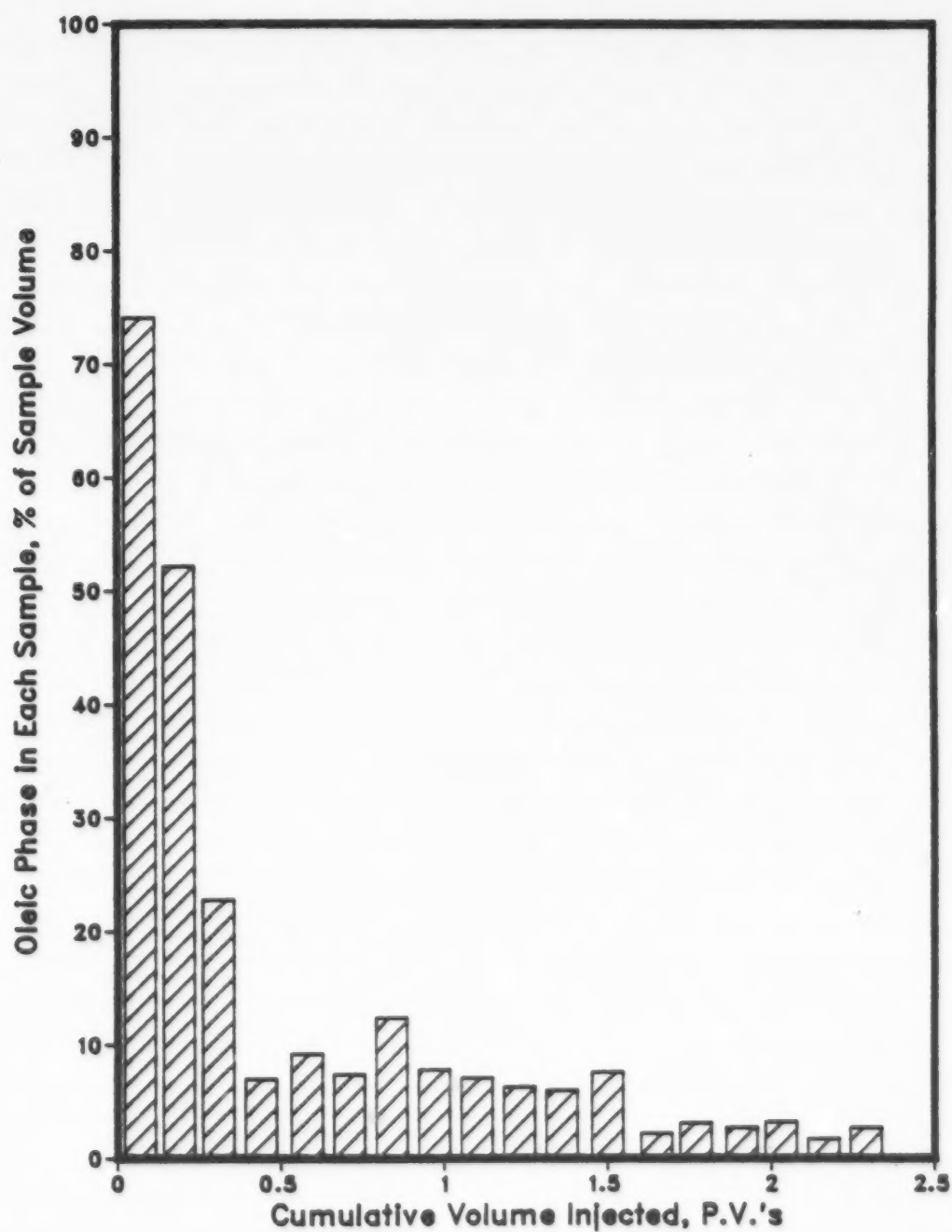


**Figure 5.85: Run 62 Gas Injection Prior to Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

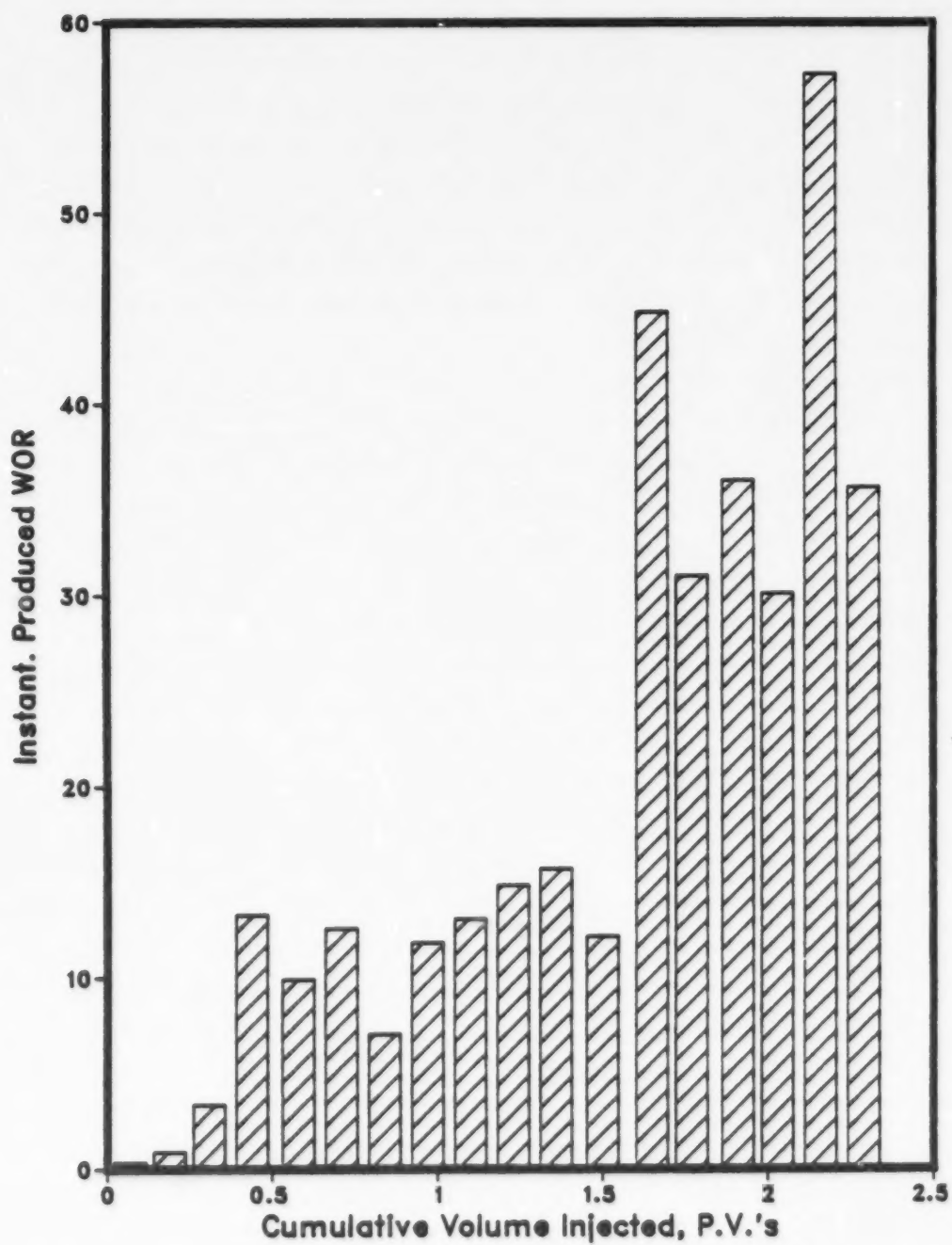
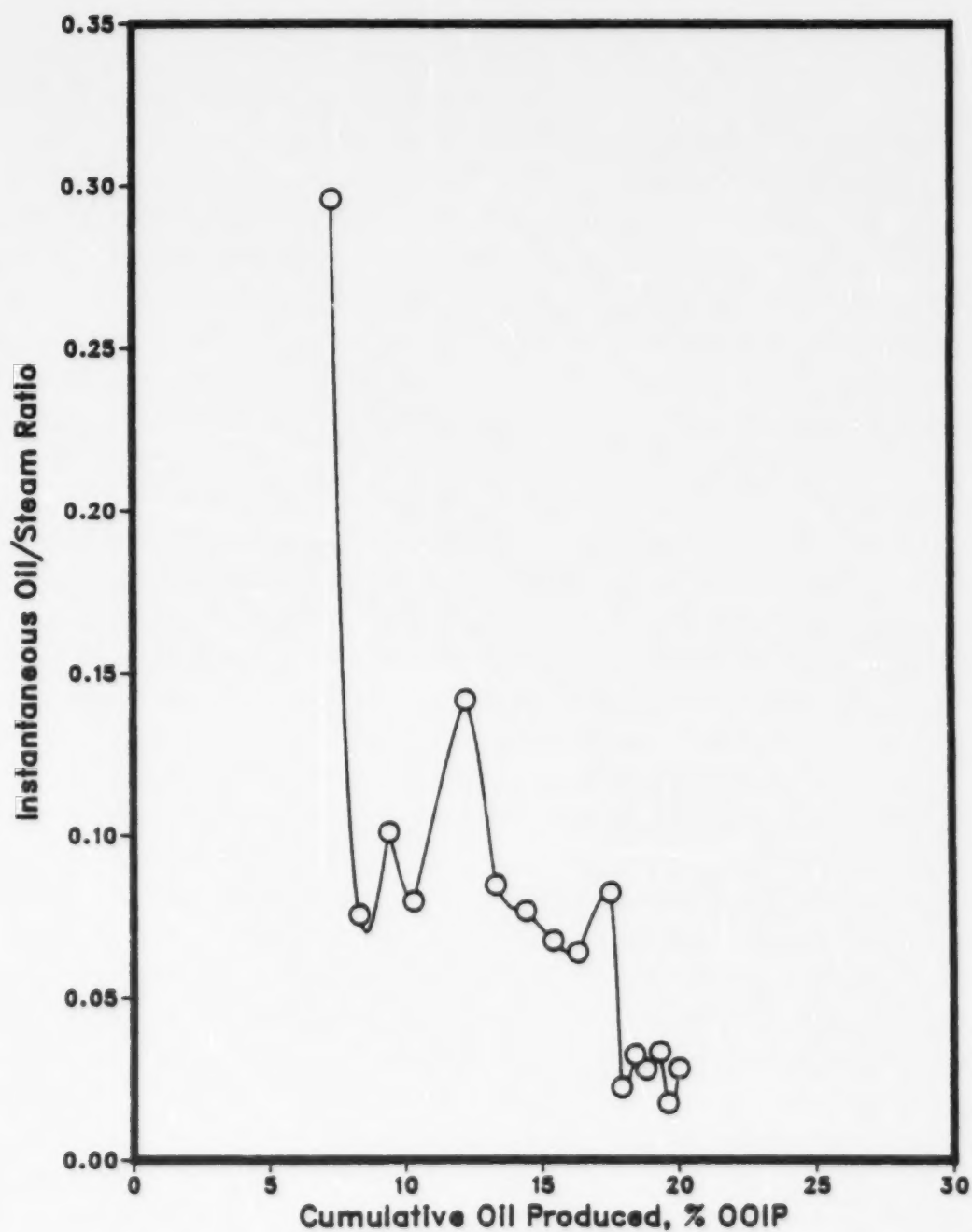


Figure 5.86 :Run 62 Gas Injection Prior to Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced



since a thicker bottom water region existed (13.6%). The cross-sectional temperature profiles of the three experiments are provided in Figures A.211-A.214 (Run 58), Figures A.223-A.226 (Run 59) and Figures A.235-A.238 (Run 62). These profiles also indicate that the existence of a gas cap permitted heat flow through the upper and lower sections at about the same rate. The cross-sectional profiles (Figures A.223-A.226) for the thicker bottom water case (Run 59) also demonstrated that heat advance was quicker in the bottom water zone during this experiment. These results imply that the gas cap aided partially in diverting the solvent and steam into the upper part of the model which reduced the heat lost to the bottom water. As well the gas cap partially diverted the solvent and steam away from the oil which resulted in less solvent and steam penetrating the oil layer and thus less oil was mobilized.

The solvent recoveries for Runs 58 (88.6%), 59 (96.7%) and 62 (94.7%) were all rather high. This indicates that solvent flowed to the production well mainly through the gas channel, resulting in less solvent mixing with the oil zone and less channelling of solvent in the bottom water zone. The lower solvent and oil recoveries for Run 58 was probably caused by less solvent channelling into the oil and more solvent flowing through the gas channel over top of the oil, therefore more heat from the injected steam was diverted to the top part of the oil zone or was lost to the bottom water and subsequently less oil was mobilized.

From the three experiments, the presence of a gas cap and bottom water had an obvious effect on the overall solvent and oil recoveries as was also described by Kasraie and Farouq Ali ^{27,28}. Results of Runs 58, 59 and 62 gave an indication that if a gas cap was present in the bottom water model more steam would be diverted away from the bottom water into the upper portion of the model.

Figure 5.87 provides a comparison of the recovery curves for a solvent-steamflood in a bottom water model (Run 50) and a solvent-steamflood with previous gas injection in a bottom water model (Run 58). Runs 50 and 58 had similar bottom water thicknesses of

10.2% and 9.8%, respectively. It is quite evident from Figure 5.87 that Run 50 (solvent-steamflood) achieved a considerably greater oil recovery than Run 58 (gas injection prior to solvent-steamflood). The main difference between the curves occurred during the initial stages of the two recovery relationships. Run 50 had a more drastic initial increase in recovery (25.4% OOIP) compared to Run 58 (18.2% OOIP) due to the solvent and oil more effectively penetrating the oil zone and creating a more stable steam displacement of oil during Run 50. Run 58 had a less pronounced solvent and oil invasion in the oil region since more solvent and oil flowed over top of the oil zone through the channel formed by the previous gas injection. Steam breakthrough was earlier and less distinct for Run 58 due to the existence of a less stable displacement of oil caused by the gas channel.

A gas cap in a reservoir can be helpful or detrimental to the effectiveness of a steam injection process depending on certain characteristics of the reservoir such as heat loss, reservoir thickness, bottom water thickness and the gas cap size. During the steamflood of a bottom water reservoir the gas cap allowed the steam to remain in the upper portion of the formation away from the bottom water, thus heating and mobilizing the inplace oil from above. How effectively the oil was mobilized from above depends on the magnitude of the heat lost to the overburden, adjacent formations and the bottom water zone. However, in the case of the solvent-steamflood process the gas cap enabled the solvent to flow over top of the oil zone. Overriding of the oil by the solvent caused fewer flow channels to form in the oil layer. Lack of solvent channelling into the oil zone hindered the penetration of the oil layer by the steam. Consequently, less oil was mobilized by the steam resulting in a decline in the overall recovery of a solvent-steamflood process as compared to its implementation in a heavy oil reservoir with bottom water but no gas cap or gas channel.

Effect of Injection-Production Interval Locations

The effect of injection-production interval locations on the success of the solvent-steamflood process in bottom water reservoirs was found to be very important. By

Figure 5.87 : Comparison of Solvent-Steamflood Run 50 & Gas Injection Prior to Solvent-Steamflood Run 58 Recoveries Performed in a Bottom Water Model

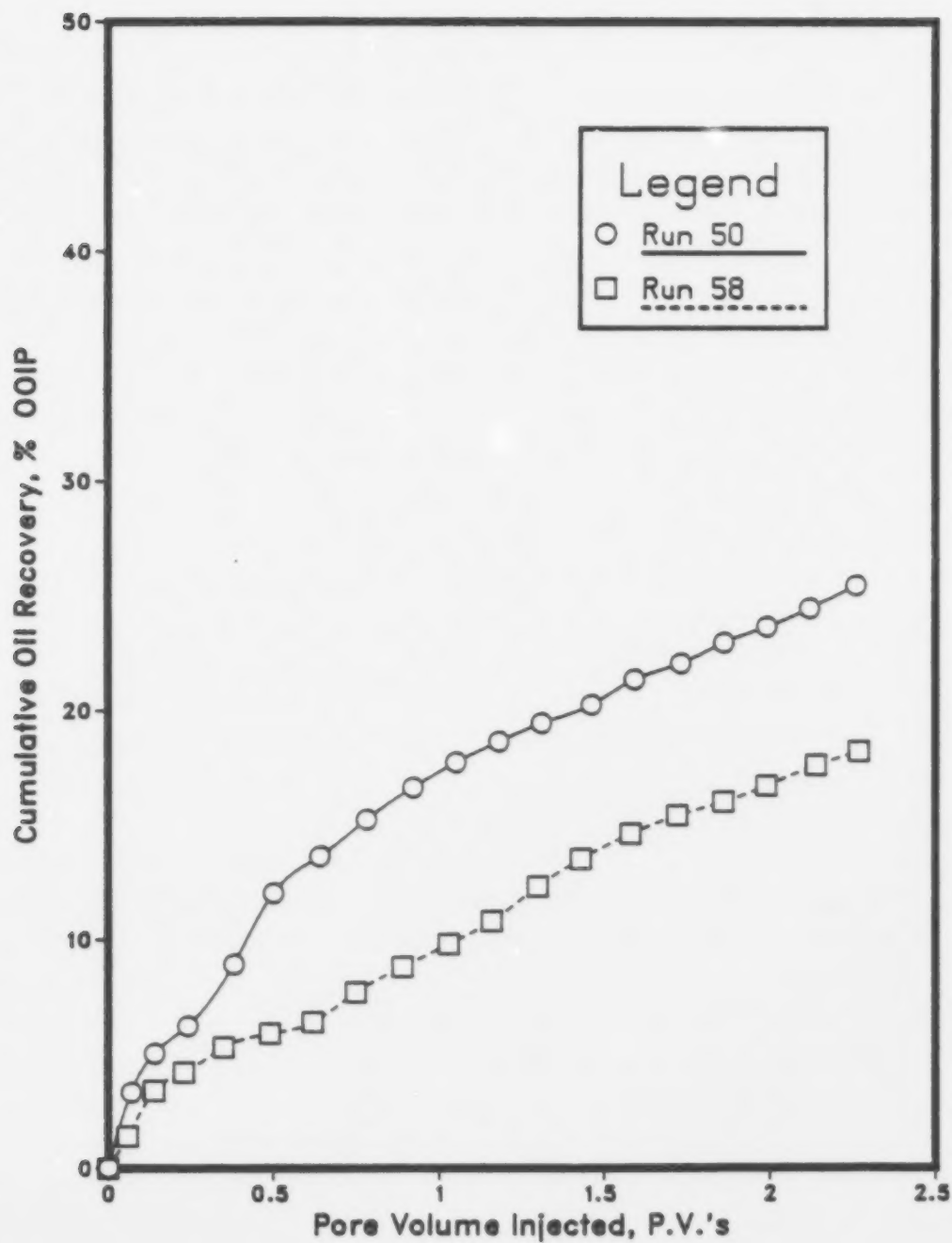
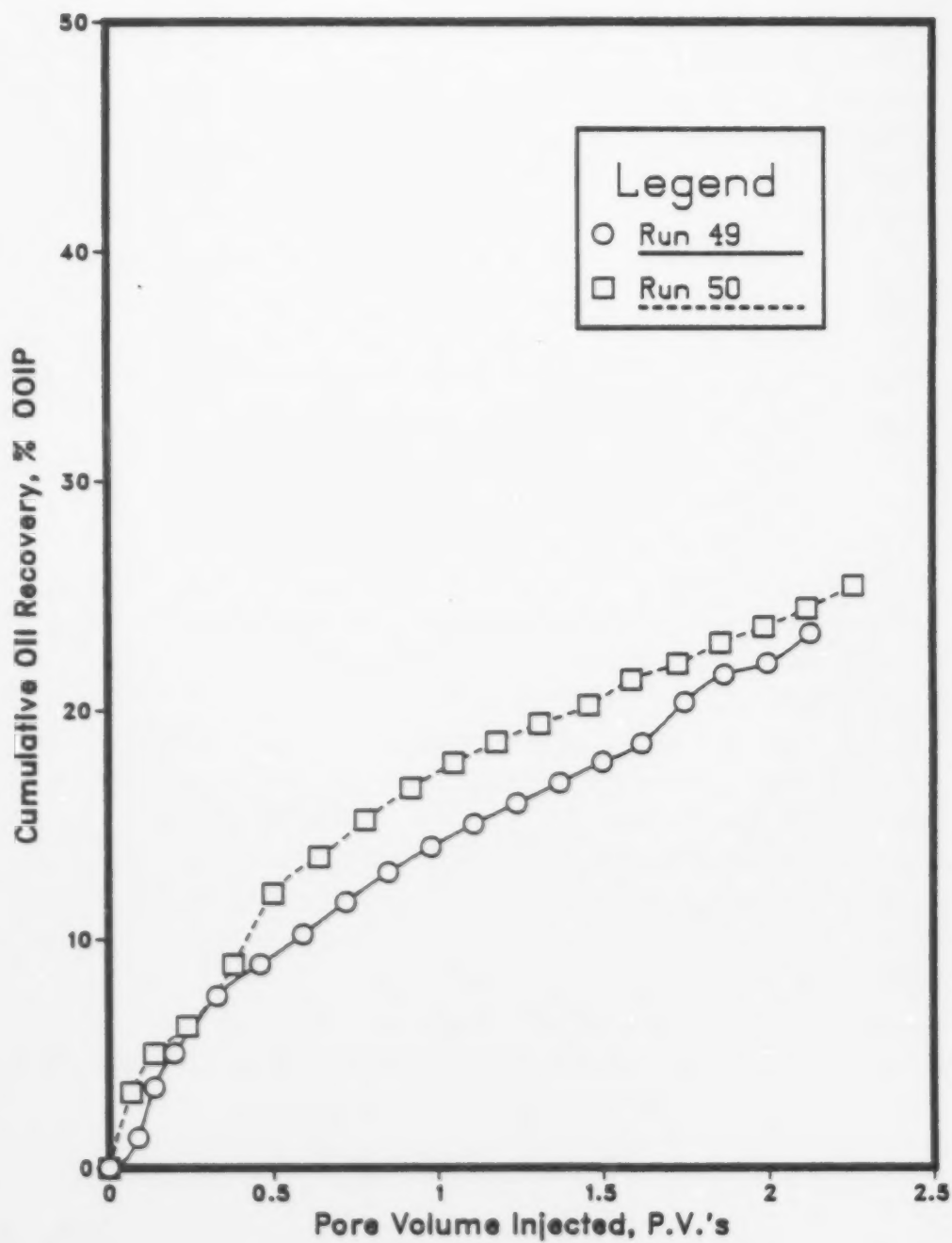


Figure 5.88 :Comparison of the Effect of Inj.-Prod. Interval Locations
For Runs 49, Inj-Entire & Prod-Upper, & Run 50, Inj-Upper & Prod-Entire



optimizing the injection-production interval positions the injected solvent and steam could be utilized most effectively to recover the inplace oil.

Two experiments were performed (Runs 49 & 50) in order to determine the effect of injection-production interval locations on the solvent-steamflood recovery from a bottom water model. Runs 49 and 50 had similar bottom water water thicknesses of 8.8% and 10.2% of the total model thickness, respectively. The injection interval was situated over the entire model thickness, while the production interval was in the top half of the model for Run 49. Whereas in Run 50 the injection was completed in the upper half of the model and production was from the entire model thickness.

A comparison of the recovery curves from the two experiments (Runs 49 & 50), provided in Figure 5.88, indicates that the most effective injection-production intervals appeared to be those used in Run 50 where injection was into the upper half and production was from the entire model thickness. As illustrated by Figure 5.88, Run 50 had a higher oil recovery than Run 49 throughout the entire run. In the case of Run 50, solvent and steam were injected into the upper half of the model and therefore less of the solvent and steam was affected by the underlying water, compared to Run 49. During Run 49, the solvent and steam were injected over the entire model thickness which resulted a larger percentage of the injected fluids being channelled by the bottom water, even though Run 49 had a slightly thinner bottom water layer. Solvent channelling in the oil zone was more extensive for Run 50 than Run 49 due to the more preferential solvent injection into the oil layer. Injection into the upper portion of the model increased solvent channelling in the oil and allowed more steam to penetrate the oil zone, causing more oil to be mobilized. However, for Run 49, less extensive solvent channelling occurred in the oil zone since injection was spread over the entire model thickness as opposed to only half the model thickness as in Run 50. Less steam penetrated the oil zone in Run 49 and a greater amount of steam was lost to the bottom water as a result of reduced solvent channelling in the oil layer and a larger injection interval, which included the bottom water zone.

An examination of the top view temperature profiles for Runs 49 (Fig. A.119-A.126) and 50 (Fig. A.131-A.138) also indicates that the steam was being used more efficiently in the upper oil zone of the model during Run 50. Figures A.119-A.126 for Run 49 show that the injected heat from the steam was travelling faster through the bottom half than the upper region of the model. Compared to the temperature contours for Run 49, the temperature profiles for Run 50 (Fig. A.131-A.138) indicate the injected heat was retained longer in the upper region of the model, where the oil was located. The cross-sectional temperature profiles provided in Figures A.127-A.130 (Run 49) and Figures A.139-A.142 (Run 50) verify these observations.

The injection interval location for Run 50 permitted more efficient use of the injected solvent and steam, by directing these fluids into the oil zone and away from the bottom water, thus yielding a higher overall oil recovery. However, for Run 49, more solvent and steam were lost to the underlying water zone, making this solvent-steamflood process less efficient than the solvent-steamflood conducted during Run 50.

Use of a Physical Barrier in a Bottom Water Steamflood

One of the objectives of this study was to investigate an alternate recovery strategy to the solvent-steamflood process, which also attempted to divert the injected steam away from the bottom water layer. The experimental results of this type of run could then be compared to the findings of the solvent-steamflood experiments in order to determine the relative effectiveness of this recovery technique. This recovery method involved the placement of a partial barrier between the bottom water and oil zone to prevent the injected steam from flowing directly into the less flow resistant bottom water. A notable advantage of using a partial bottom water barrier as discussed by Alikhan and Farouq Ali⁶⁷ was that a barrier at the water-oil contact of a reservoir aided in reducing water coning. Runs 63 and 64 attempted to represent a bottom water reservoir containing a partial barrier which could be created in the field by selectively injecting a suitable blocking agent, such as a foam or

gel, at the oil-water contact. The purpose of the partial barrier was to help prevent the steam from travelling directly into the bottom water so that it could flow through the overlying oil zone and more efficiently heat and mobilize the inplace oil. A thin plastic sheet was placed between the bottom water layer and the oil layer to represent a partial bottom water barrier. The barrier installed in the model extended radially outward from the injection well in the shape of a quarter circle with a radius of 16 inches. The area covered by the partial barrier was approximately 20% of the total model area as illustrated in the following schematic diagram (Figure 5.89).

Runs 63 and 64 were continuous steamfloods in a bottom water model containing a partial bottom water barrier between the oil zone and the underlying bottom water interval. The results of Runs 63 and 64 are given in tabular form and are displayed in Tables 5.22 and 5.23, respectively.

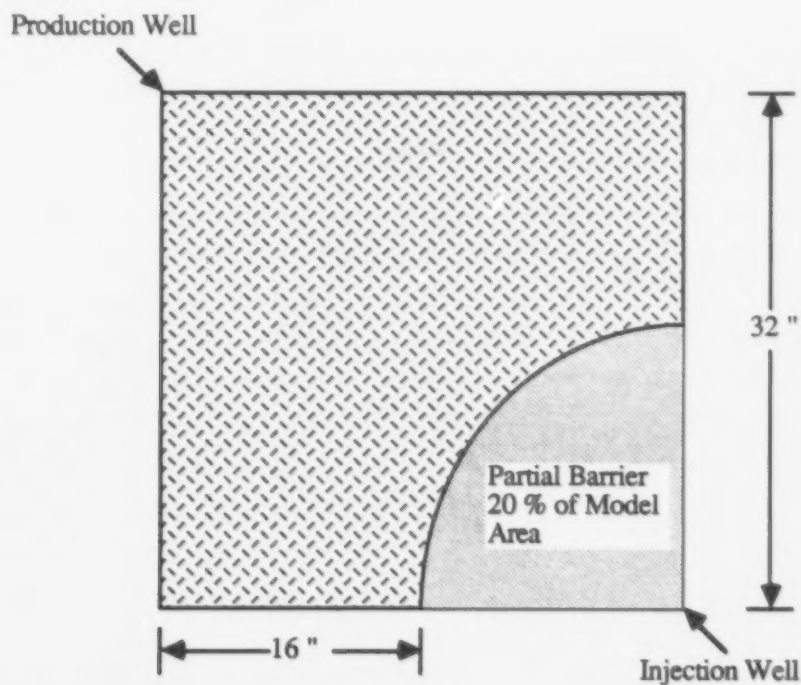


Figure 5.89 :Schematic of Partial Barrier Installed in a Bottom Water Model

The recovery curves plotted for Runs 63 and 64 are presented in Figures 5.90 and 5.94, respectively. The overall oil recovery for Run 63 (17.0% OOIP) was less favourable than that obtained in Run 64 (22.0% OOIP). The reason for the lower recovery in Run 63 is the thicker bottom water layer (15.4% of gross model thickness). Run 64 had a bottom water region that was 9.9% of the gross model thickness. Since less bottom water existed in Run 64 a larger percentage of the injected heat was utilized in mobilizing the oil instead of being scavenged by the bottom water. The recovery curves for Runs 63 (Figure 5.90) and 64 (Figure 5.94) appeared to have much slower initial recovery responses compared to the recovery curves of most of the previous solvent-steamflood experiments (Runs 49, 50, 51, 53 & 54). This suggests that the partial barrier experiments were not as effective as the solvent-steamflood runs since the steam appeared to have a tendency to travel between the partial barrier and the oil zone out to the point in the model where the barrier no longer existed. During the partial barrier experiments a larger amount of injected heat moved downward into the detrimental bottom water region with a smaller portion filtering upward into the oil zone. However, during the initial stages of the solvent-steamflood the steam flowed directly into the oil zone through the solvent channels, which more effectively utilized the oil mobilizing capability of the injected steam. This would explain the slower initial recovery responses of the partial barrier experiments. In the later stages of Run 63 (Figures 5.90) and Run 64 (Figure 5.94) the recovery responses become similar (ie. increased) to the responses observed in the recovery curves of the solvent-steamflood experiments. This indicates that some of the heat in the steam moved upward into the oil region resulting in a larger amount of oil being mobilized and subsequently produced.

The bar plots of the volume percentage of oleic phase in each sample versus cumulative volume injected and instantaneous produced WOR versus cumulative volume injected are provided for Runs 63 (Fig. 5.91 & 5.92) and 64 (Fig. 5.95 & 5.96). Study of the bar plots for both experiments shows that the thicker bottom water layer of Run 63

Table 5.22: Run 63 Steamflood of Bottom Water Model With a Partial Barrier

HC Pore Volume :	11820.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	15245.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	36.3%	Boiler Feed Flow Rate :	29.20 cc/min
Initial Oil Satn. :	77.5%	Total Flow Rate of Steam :	229.20 cc/min
Initial H2O Satn. :	22.5%	Bottom Water Layer Thickness :	15.4% (% Gross Model Thickness)
Steam Vol. Inj. :	34460.0 cc (2.26 PV)		

Net Oil Recovery : 17.0 %

Final Oil Saturation : 64.3 %

Cyl. No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	(P.V.)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	[%OOIP]	Oil-Steam Ratio	Inst. Prod. WOR	Inst. Oil Prod. % of Sample
1	2090	2090	0.14	45	45	0.4%	0.0220	45.44	2.2%
2	1940	4030	0.26	10	55	0.5%	0.0052	193.00	0.5%
3	2125	6155	0.40	45	100	0.8%	0.0216	46.22	2.1%
4	2020	8175	0.54	50	150	1.3%	0.0254	39.40	2.5%
5	2055	10230	0.67	85	235	2.0%	0.0431	23.18	4.1%
6	1940	12170	0.80	135	370	3.1%	0.0748	13.37	7.0%
7	2060	14230	0.93	195	565	4.8%	0.1046	9.56	9.5%
8	1900	16130	1.06	215	780	6.6%	0.1276	7.84	11.3%
9	2125	18255	1.20	165	945	8.0%	0.0842	11.88	7.8%
10	1985	20240	1.33	125	1070	9.1%	0.0672	14.88	6.3%
11	2045	22285	1.46	130	1200	10.2%	0.0679	14.73	6.4%
12	1970	24255	1.59	120	1320	11.2%	0.0649	15.42	6.1%
13	2040	26295	1.72	200	1520	12.9%	0.1087	9.20	9.8%
14	1950	28245	1.85	170	1690	14.3%	0.0955	10.47	8.7%
15	2050	30295	1.99	130	1820	15.4%	0.0677	14.77	6.3%
16	1985	32280	2.12	115	1935	16.4%	0.0615	16.26	5.8%
17	2180	34460	2.26	75	2010	17.0%	0.0356	28.07	3.4%

Figure 5.90 :Run 63 Steamflood of Bottom Water Model With a Partial Barrier
Cumulative Oil Recovery Vs. Pore Volumes Injected

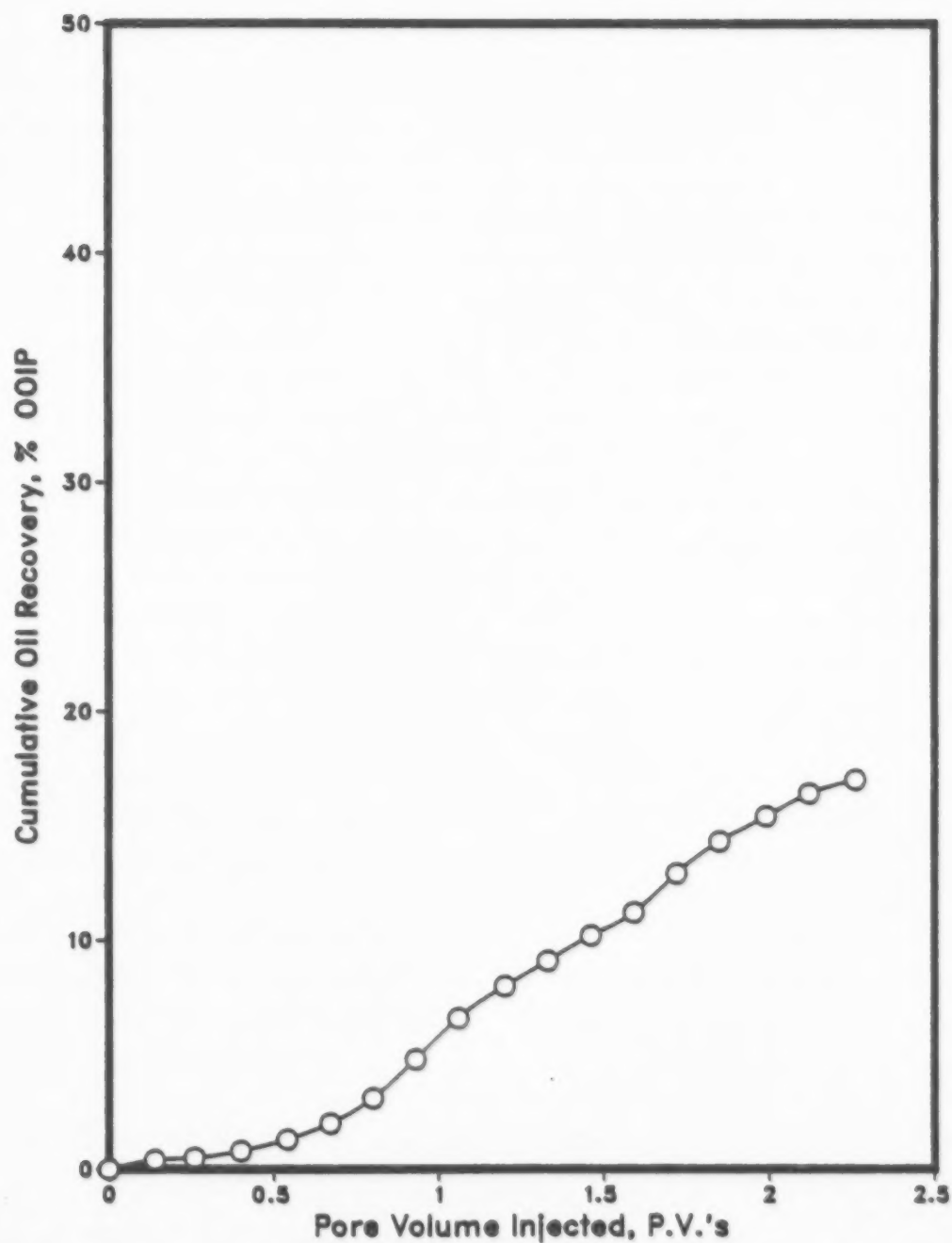


**Figure 5.91 :Run 63 Steamflood of Bottom Water Model With a Partial Barrier
Oleic Phase in Each Sample Vs. Cumulative Volume Injected**

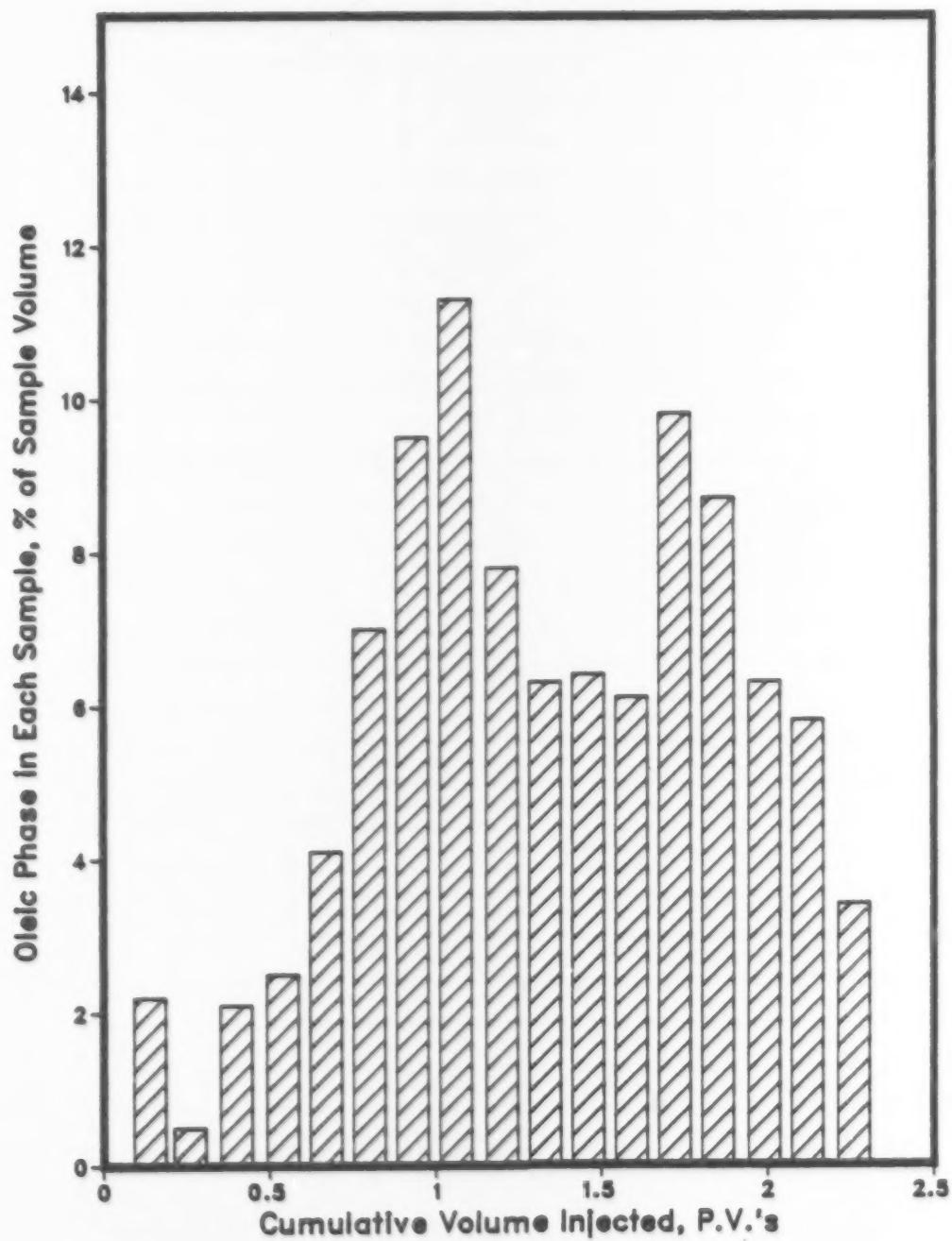


Figure 15.92 :Run 63 Steamflood of Bottom Water Model With a Partial Barrier
Instantaneous Produced WOR Vs. Cumulative Volume Injected

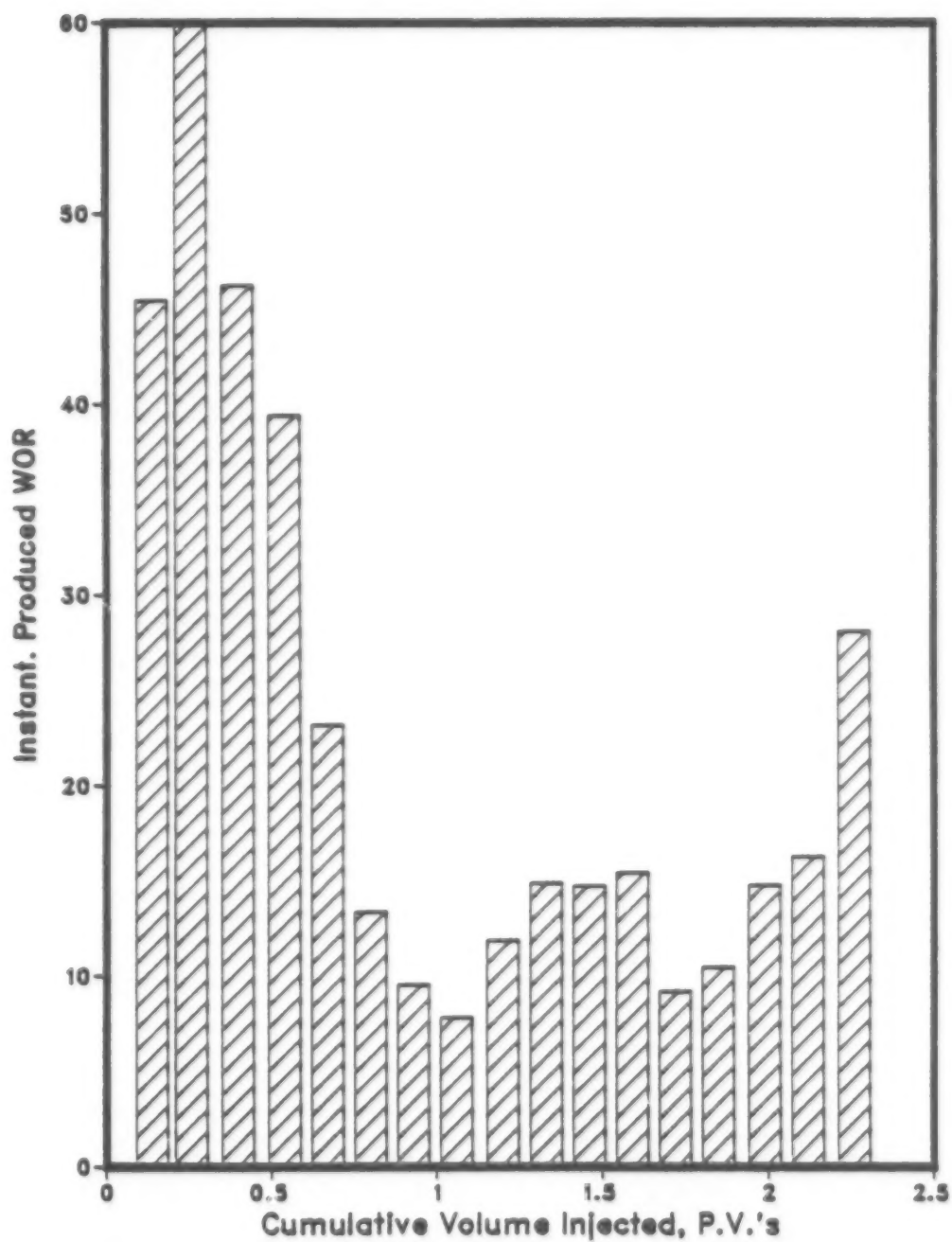


Figure 5.93 :Run 63 Steamflood of Bottom Water Model With a Partial Barrier
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced

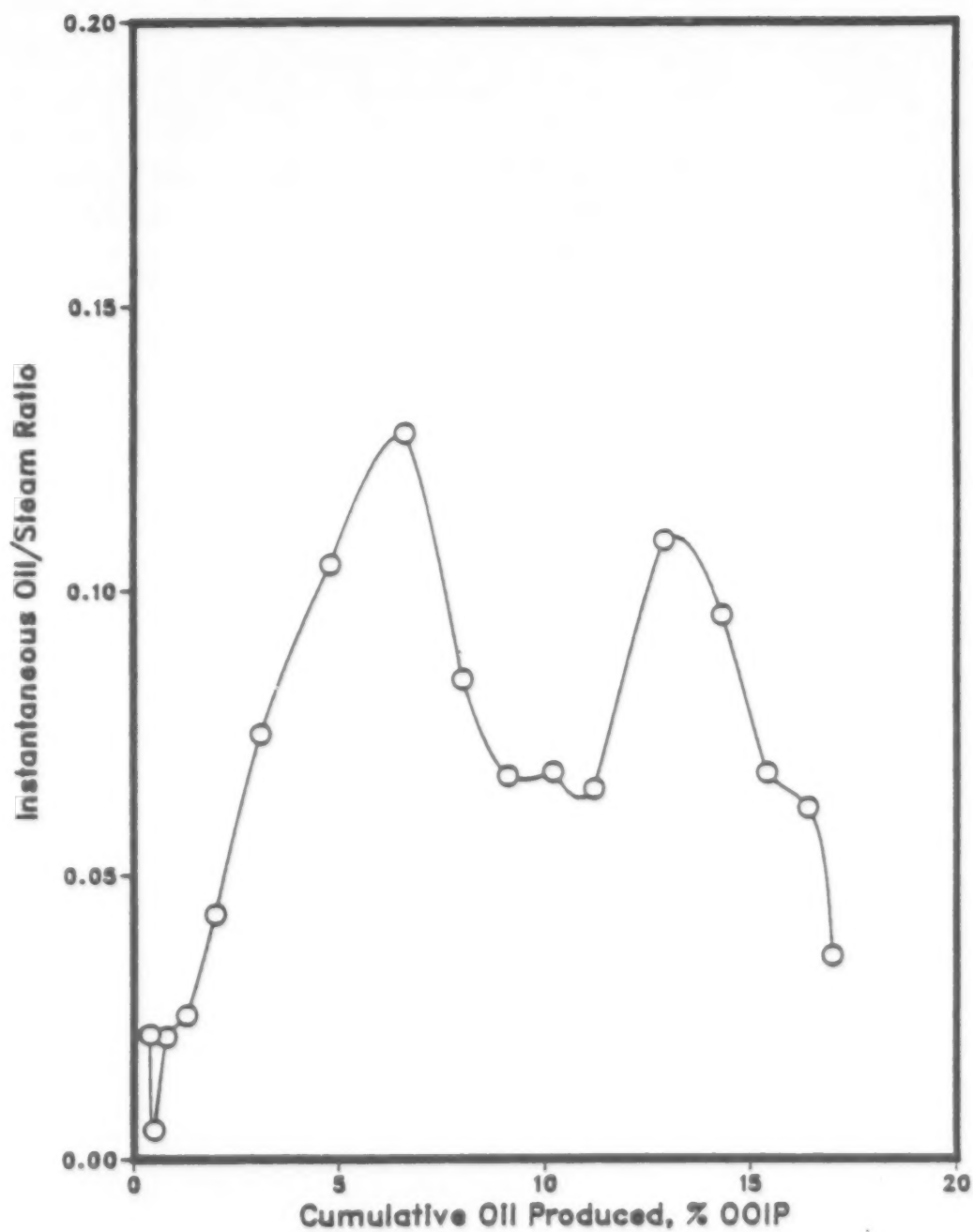


Table 5.23: Run 64 Steamflood of Bottom Water Model With a Partial Barrier

HC Pore Volume:	13500.0 cc	Type of Oil Used:	Faxam-100
Pore Volume:	15425.0 cc	Initial Model Temperature:	3.00 C
Bulk Volume:	42005.0 cc	Water Feed Flow Rate:	200.00 cc/min
Porosity:	36.7%	Boiler Feed Flow Rate:	29.20 cc/min
Initial Oil Satn.:	87.5%	Total Flow Rate of Steam:	229.20 cc/min
Initial H ₂ O Satn.:	12.5%	Bottom Water Layer Thickness:	9.9% (% Gross Model Thickness)
Steam Vol. Inj.:	34950.0 cc (2.27 PV)		

Final Oil Saturation : 68.2%

Net Oil Recovery : 22.0%

Cyl. No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj.		Oil Prod. (cc)	Cum. Oil Rec. (%OOIP)		Oil-Steam Ratio	Inst Prod. WOR	Inst. Oil Prod. % of Sample
		(cc)	(P.V.)		(cc)	(%)			
1	1975	1975	0.13	510	510	3.8%	0.3481	2.87	25.8%
2	2235	4210	0.27	155	665	4.9%	0.0745	13.42	6.9%
3	1980	6190	0.40	200	865	6.4%	0.1124	8.90	10.1%
4	2105	8295	0.54	230	1095	8.1%	0.1227	8.15	10.9%
5	2045	10340	0.67	275	1370	10.1%	0.1554	6.44	13.4%
6	2110	12450	0.81	145	1515	11.2%	0.0738	13.55	6.9%
7	1925	14375	0.93	180	1695	12.6%	0.1032	9.69	9.4%
8	2095	16470	1.07	145	1840	13.6%	0.0744	13.45	6.9%
9	2015	18485	1.20	110	1950	14.4%	0.0577	17.32	5.5%
10	2085	20570	1.33	140	2090	15.5%	0.0720	13.89	6.7%
11	1940	22510	1.46	125	2215	16.4%	0.0689	14.52	6.4%
12	2060	24570	1.59	125	2340	17.3%	0.0646	15.48	6.1%
13	1955	26525	1.72	135	2475	18.3%	0.0742	13.48	6.9%
14	2200	28725	1.86	120	2595	19.2%	0.0577	17.33	5.5%
15	1960	30685	1.99	140	2735	20.3%	0.0769	13.00	7.1%
16	2200	32885	2.13	140	2875	21.3%	0.0680	14.71	6.4%
17	2065	34950	2.27	100	2975	22.0%	0.0509	19.65	4.8%

Figure 5.94 :Run 64 Steamflood of Bottom Water Model With a Partial Barrier
Cumulative Oil Recovery Vs. Pore Volumes Injected

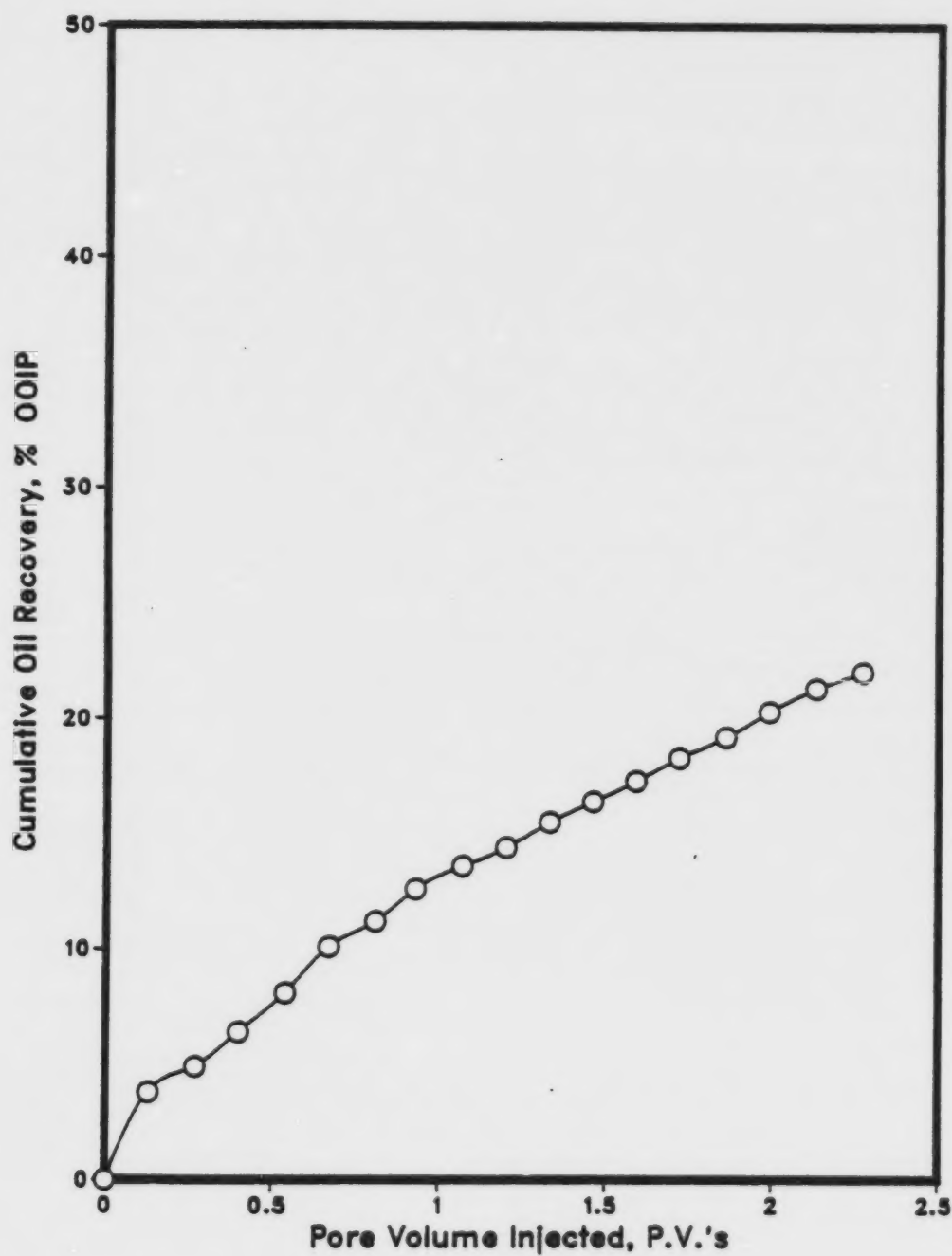


Figure 5.95 :Run 64 Steamflood of Bottom Water Model With a Partial Barrier
Oleic Phase in Each Sample Vs. Cumulative Volume Injected

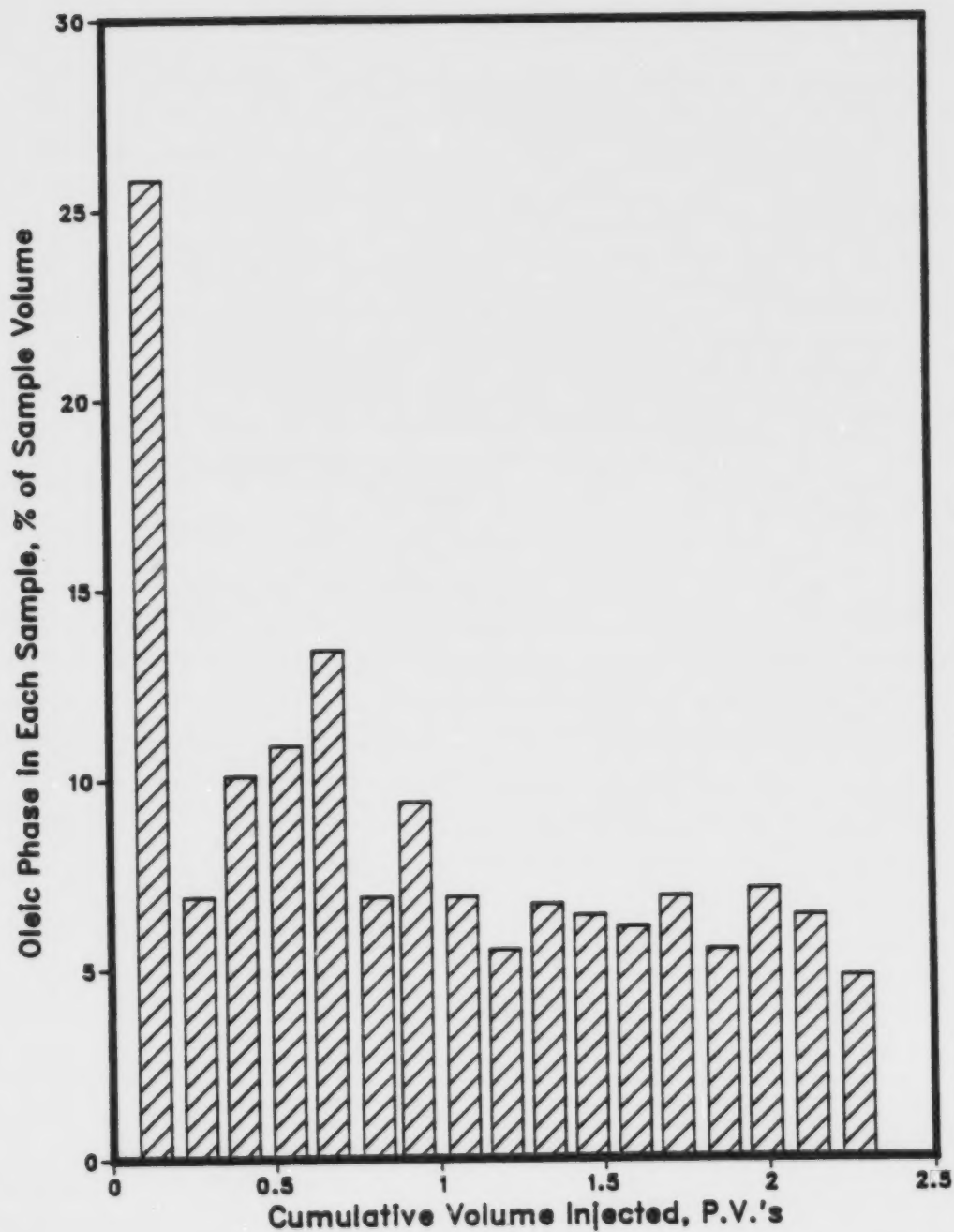


**Figure 5.96 :Run 64 Steamflood of Bottom Water Model With a Partial Barrier
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

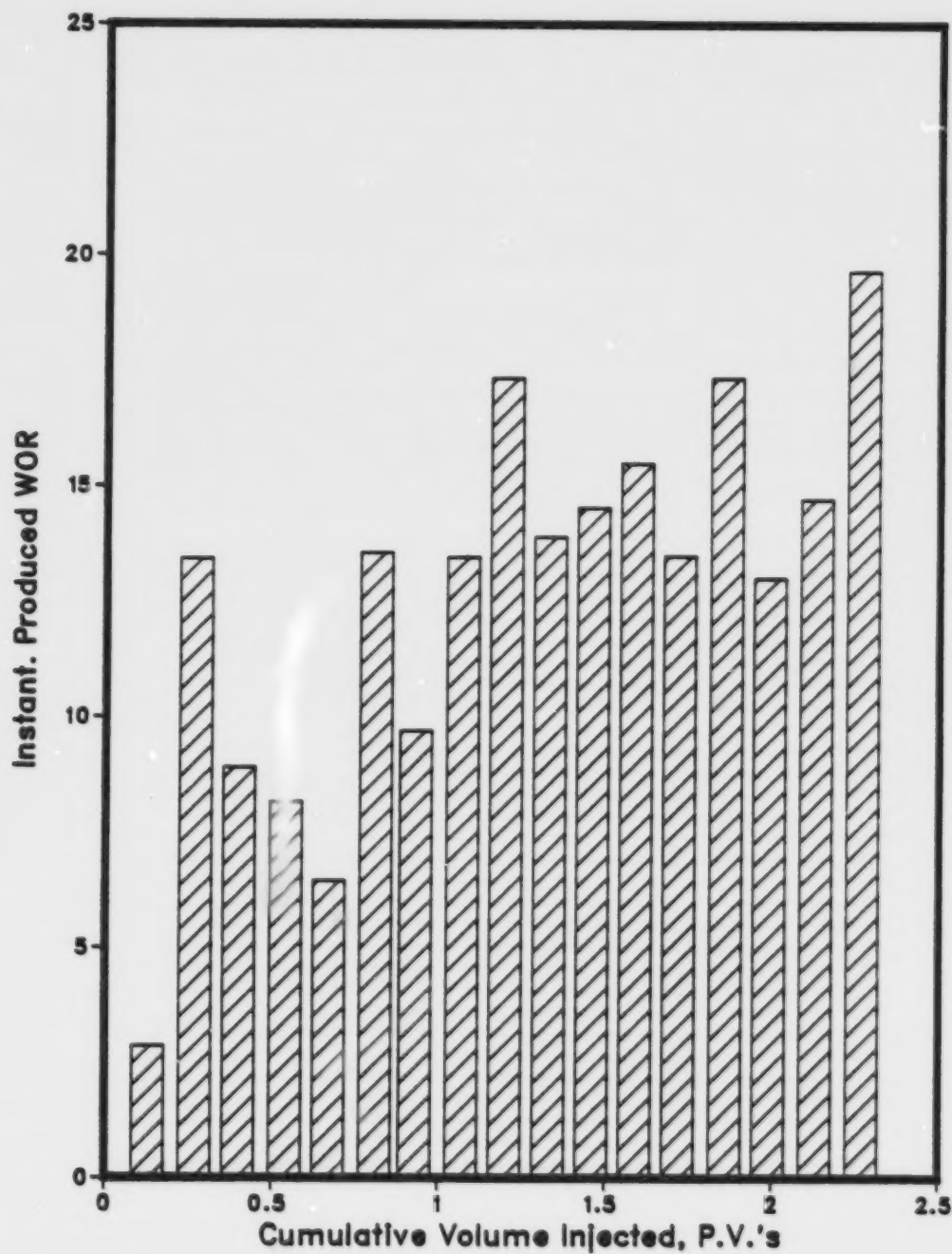
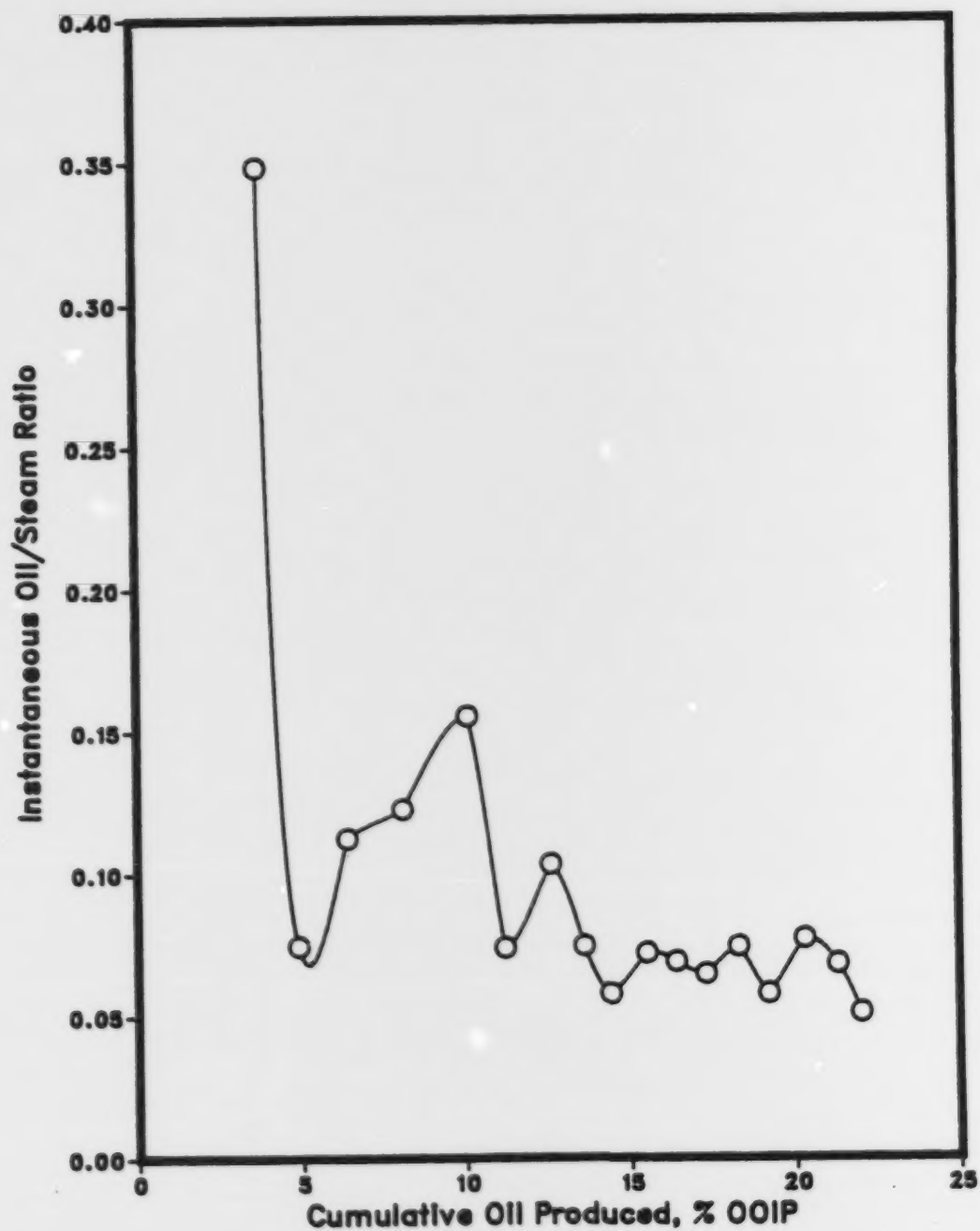


Figure 5.97 :Run 64 Steamflood of Bottom Water Model With a Partial Barrier
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced



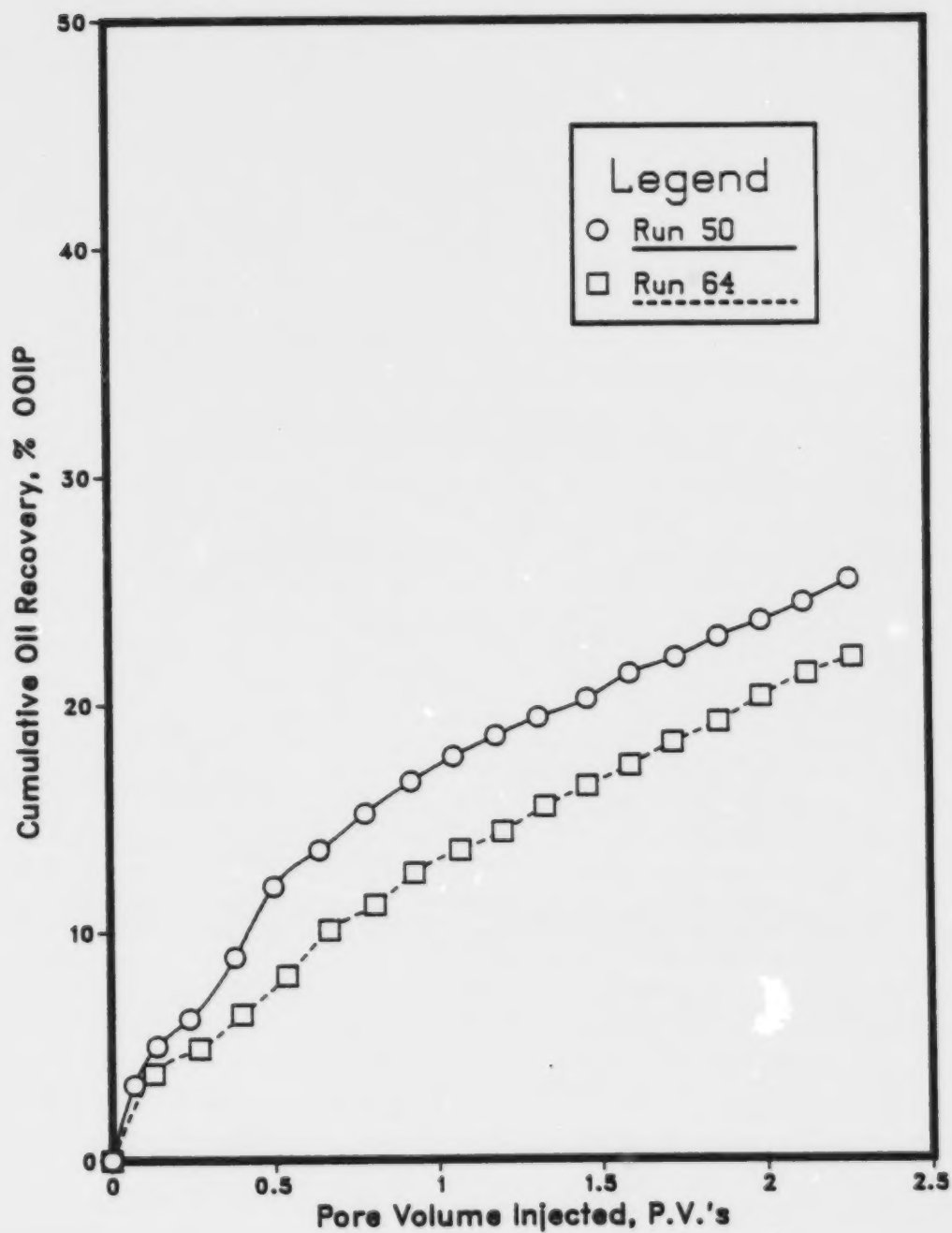
resulted in earlier solvent and steam breakthrough and a less stable displacement of the oil within the model as compared to Run 64.

The plots of instantaneous oil/steam ratio versus cumulative oil produced for Runs 63 (Figure 5.93) and 64 (Figure 5.97) also indicate the adverse effects of the thicker bottom water zone in Run 63. The average instantaneous oil/steam ratio in Run 63 (Figure 5.93) was somewhat lower than the average instantaneous oil/steam ratio in Run 64 (Figure 5.97) which was due to the larger bottom water zone in Run 63. The thicker bottom water layer in Run 63 caused a greater portion of water to be produced in each recovery sample of the experiment.

The temperature profiles for Runs 63 (Figures A.239-A.246) and 64 (Figures A.251-A.258) illustrate that during both experiments the heat advanced quicker through the lower portion of the model due to the presence of the bottom water. Due to the thicker bottom water in Run 63 the heat advanced faster through the lower half of the model and more slowly through the upper half as compared to Run 64. Since the injected heat appeared to move faster through the upper half (oil zone) of the model during Run 64 it was concluded that less heat was lost to the underlying bottom water. Therefore Run 64 made better use of the injected steam than Run 63. A comparison of the temperature profiles of Runs 63 and 64 with Runs 49, 50, 51, 53 and 54 shows that the heat travelled faster in the lower region and slower in the upper region of the model during Runs 63 and 64. This indicates that the solvent-steamflood technique had a greater thermal efficiency than the partial barrier recovery strategy, due to reduced heat loss to the bottom water during the solvent-steamflood experiments. The cross-sectional temperature profiles for Runs 63 (Fig. A.247-A.250) and 64 (Fig. A.259-A.262) confirm the previous observations.

A comparison of the results of Runs 63 and 64 with the results of the previous solvent-steamflood experiments (Runs 49, 50, 51, 53 & 54) also indicates that the solvent-steamflood strategy was a more effective recovery technique. Figure 5.98 provides a

Figure 5.98 :Comparison of Recoveries of a Solvent-Steamflood With Bottom Water Run 50 & a Steamflood with a Partial Bottom Water Barrier Run 64



comparison of a typical solvent-steamflood process conducted in a bottom water model (Run 50) and a conventional steamflood performed in the presence of a partial bottom water barrier (Run 64), both of which had similar bottom water thicknesses of 10.2% and 9.9% of the total model thickness, respectively. The comparison indicates that the recovery obtained in Run 50 (25.4% OOIP) was somewhat higher than that yielded by Run 64 (22.0% OOIP) even though Run 50 had a slightly thicker bottom water layer. The more favorable outcome of the solvent-steamflood process was due to steam being more directly injected into the oil region through the solvent channels. The injected heat had to travel upwards in the oil zone during the partial barrier experiments, which was not as thermally efficient as a solvent-steamflood. It was also reported by Alikhan and Farouq Ali ⁶⁷ that the creation of a barrier in the field is generally difficult which makes this recovery method even less attractive.

Even though the solvent-steamfloods appeared to utilize the injected heat more efficiently, the partial barrier recovery technique did show promise. As well as a solvent-steamflood, the partial barrier method could also be used as a more thermally efficient alternative to a straight steamflood in a bottom water formation. Depending on the difference in costs and difficulties between injecting solvent (ie. solvent-steamflood) or creating a partial bottom water barrier as well as the comparative overall oil and solvent recoveries yielded for each recovery technique, the partial barrier method may in fact be more economical to implement in the field than a solvent-steamflood process. But from the experimental results of this study the solvent-steamflood appeared to be a better recovery process.

Effectiveness of Waterflooding Prior to Solvent and Steam Injection

Another objective of the research conducted was to determine the effectiveness of the solvent-steamflood process as an enhanced recovery technique. In Runs 47 and 48 a solvent-steamflood was conducted following a waterflood of a homogeneous model.

Both Runs 47 and 48 involved waterflooding the oil saturated model prior to injecting 0.10 pore volume of solvent and continuously steamflooding. The results for Runs 47 and 48 are provided in Tables 5.24 & 5.25 and 5.26 & 5.27, respectively. Initial model characteristics and the experimental results from the two runs were quite similar in many aspects such as porosities, initial and final oil and water saturations, and oil and solvent recoveries. The curves and bar plots provided for Runs 47 and 48 were also quite similar.

The similar recovery curves for the experiments are shown in Figures 5.99 (Run 47) and 5.103 (Run 48). A sharp rise is seen in the initial part of Figures 5.99 and 5.103 followed by a gradual decrease in the slope up until solvent injection and steamflooding. The initial rise in the curves represented the banking of oil at the production well due to waterflooding. The following decrease in the slope of the curves represents the breakthrough of the injected water. Further oil production occurred after water breakthrough due to the injected water displacing oil still existing in the model. The waterflood was continued until a water-oil ratio of approximately 20:1 was achieved. This value was chosen since many field waterflood operations are based on a WOR cutoff between 15 to 20. During solvent injection, the curves levelled off due to solvent mobilizing a small portion of oil in the model by viscosity reduction. Initiation of the steamflood resulted in another rise in the recovery curves because the oil mobilized by the solvent injection tended to form a bank in front of the steam zone. The mobilized oil was subsequently produced leading to a substantial increase in oil recovery at this stage of the experiment. After the steep increase, the slope of the recovery curves gradually declined due to the breakthrough of the injected steam at the production well. The gradual increase in the curves after steam breakthrough represents the additional oil recovered from both swept and unswept regions as a result of the steam mobilizing additional oil.

The bar plots of volume as a percentage of oleic phase in each sample collected versus the cumulative volume injected and instantaneous water/oil ratio versus cumulative

Table 5.24 : Run 47A Waterflood Prior to Solvent-Steamflood of Homogeneous Model

HC Pore Volume :	13125.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	14110.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	33.6%	Initial Oil Saturation :	93.0%
		Initial Water Saturation :	7.0%

Net Oil Recovery : 19.1% Final Oil Saturation : 75.3%

Cylinder No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	Cum. Vol. Inj. (P.V.)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	Cum. Oil Rec. (%OOIP)	Inst. Prod. WOR	Inst. Oil Prod. % of Sample
1	1830.0	1830.0	0.13	1055.0	1055.0	8.0%	0.73	57.7%
2	2010.0	3840.0	0.27	290.0	1345.0	10.2%	5.93	14.4%
3	1955.0	5795.0	0.41	260.0	1605.0	12.2%	6.52	13.3%
4	2005.0	7800.0	0.55	165.0	1770.0	13.5%	11.15	8.2%
5	1960.0	9760.0	0.69	150.0	1920.0	14.6%	12.07	7.7%
6	2060.0	11820.0	0.84	125.0	2045.0	15.6%	15.48	6.1%
7	1940.0	13760.0	0.98	110.0	2155.0	16.4%	16.64	5.7%
8	2030.0	15790.0	1.12	95.0	2250.0	17.1%	20.37	4.7%
9	1925.0	17715.0	1.26	85.0	2335.0	17.8%	21.65	4.4%
10	2005.0	19720.0	1.40	85.0	2420.0	18.4%	22.59	4.2%
11	1960.0	21680.0	1.54	85.0	2505.0	19.1%	22.06	4.3%

Table 5.25: Run 47B Solventflood Following a Waterflood of Homogeneous Model

HC Pore Volume:	10620.0 cc	Type of Oil Used:	Faxam-100
Pore Volume:	14110.0 cc	Initial Model Temperature:	3.00 C
Bulk Volume:	42005.0 cc	Water Feed Flow Rate:	200.00 cc/min
Porosity:	33.6%	Boiler Feed Flow Rate:	29.20 cc/min
Initial Oil Satn.:	75.3%	Total Flow Rate of Steam:	229.20 cc/min
Initial H ₂ O Satn.:	24.7%	Solvent Flow Rate:	200.00 cc/min
Solvent Vol. Inj.:	1400.0 cc (10.0% PV)	Steam Vol. Injected:	27235 cc (1.93 PV)

Net Oil Recovery : 33.5%

Solvent Recovery : 44.9%

Final Oil Saturation : 61.9%

Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj. (cc)	Cum. Vol. Inj.		HC Prod. (cc)	Oil Prod. (cc)	Cum. Oil Rec.		Cum. Sol. Rec. (cc)	Cum. Sol. Rec. (%)		Oil-Steamm Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample
			(cc)	(P.V.)			(cc)	(%OOIP)		(cc)	(%)			
1	6%	1340	1340	0.09	45	42	42	0.3%	3	0.2%	0.0000	28.78	3.4%	
2	60%	1440	2780	0.20	960	384	426	3.2%	579	41.4%	0.0000	0.50	66.7%	
3	12%	1820	4600	0.33	260	229	655	5.0%	610	43.6%	0.1667	6.00	14.3%	
4	6%	2070	6670	0.47	190	179	834	6.4%	621	44.4%	0.1011	9.89	9.2%	
5	4%	1980	8650	0.61	120	115	949	7.2%	626	44.7%	0.0645	15.50	6.1%	
6	2%	2100	10750	0.76	100	98	1047	8.0%	628	44.9%	0.0500	20.00	4.8%	
7	1%	1920	12670	0.90	80	79	1126	8.6%	629	44.9%	0.0435	23.00	4.2%	
8	0%	1895	14565	1.03	75	75	1201	9.2%	629	44.9%	0.0412	24.27	4.0%	
9	0%	1975	16540	1.17	85	85	1286	9.8%	629	44.9%	0.0450	22.24	4.3%	
10	0%	2000	18540	1.31	90	90	1376	10.5%	629	44.9%	0.0471	21.22	4.5%	
11	0%	2060	20600	1.46	150	150	1526	11.6%	629	44.9%	0.0785	12.73	7.3%	
12	0%	2030	22630	1.60	115	115	1641	12.5%	629	44.9%	0.0601	16.65	5.7%	
13	0%	2005	24635	1.75	85	85	1726	13.2%	629	44.9%	0.0443	22.59	4.2%	
14	0%	2000	26635	1.89	80	80	1806	13.8%	629	44.9%	0.0417	24.00	4.0%	
15	0%	2000	28635	2.03	85	85	1891	14.4%	629	44.9%	0.0444	22.53	4.3%	

Figure 5.99 :Run 47 Waterflood Followed by Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

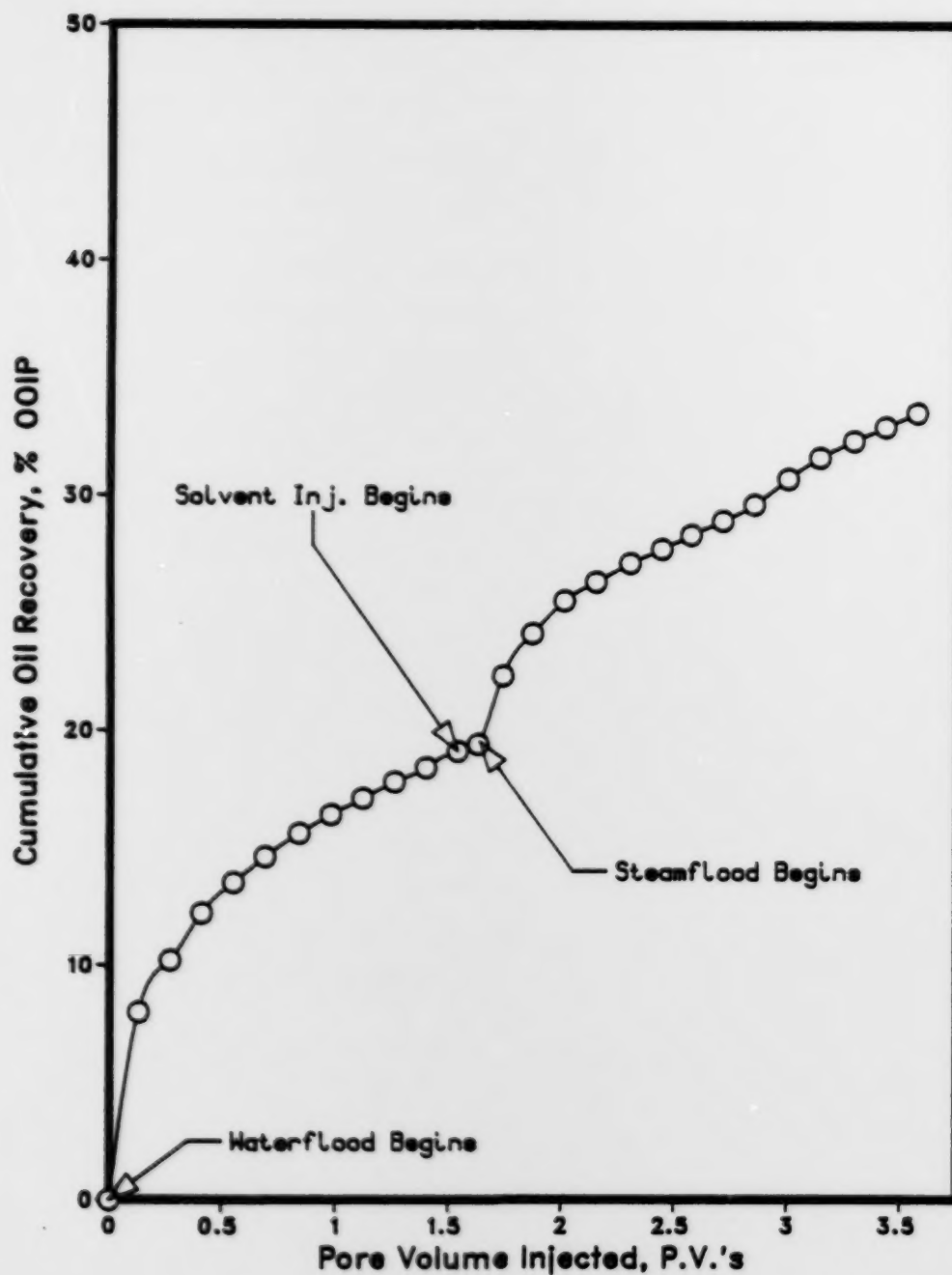


Figure 5.100 : Run 47 Waterflood Followed By Solvent-Steamflood
Oleic Phase in Each Sample Vs. Cumulative Volume Injected

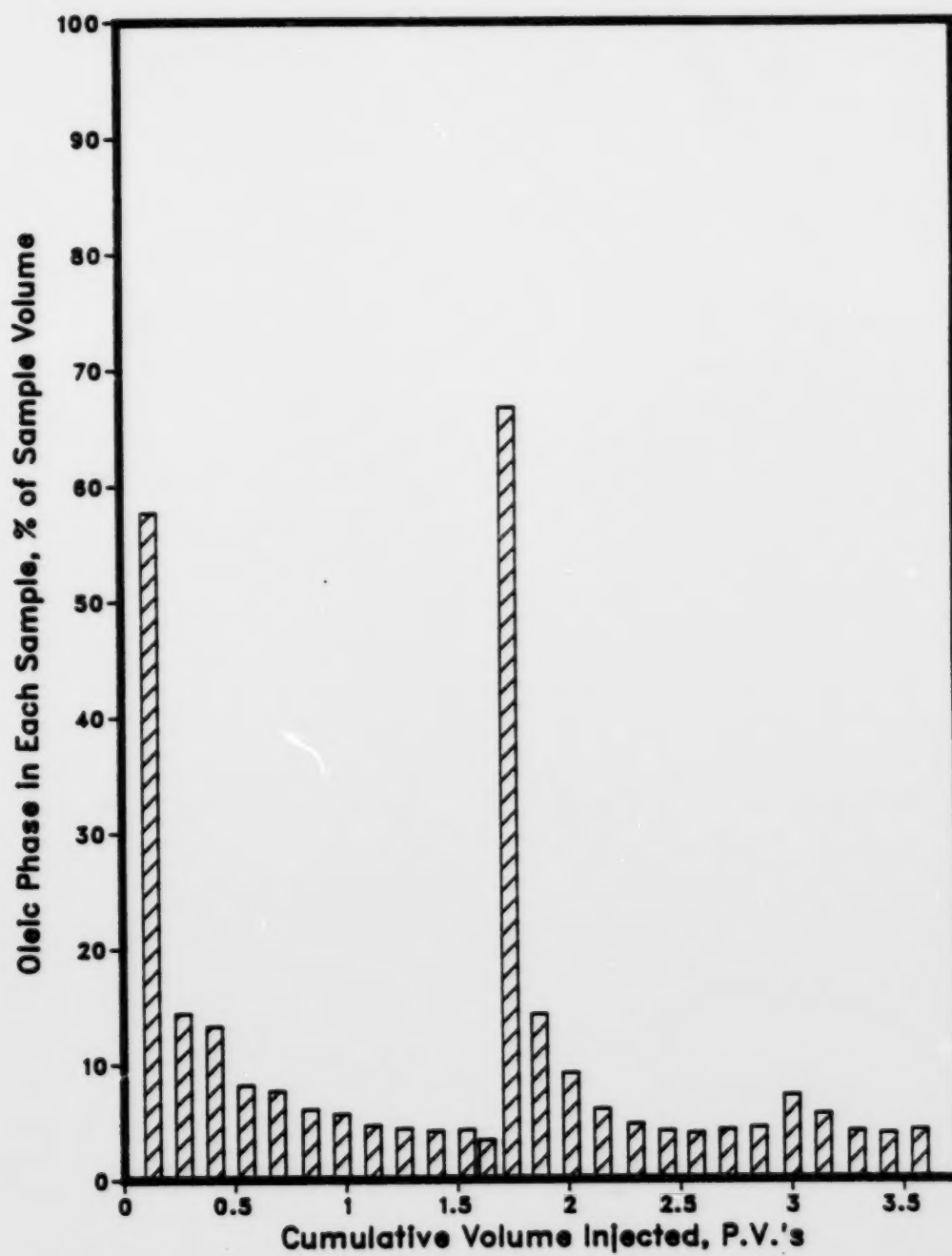


**Figure 5.101 :Run 47 Waterflood Followed By Solvent--Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

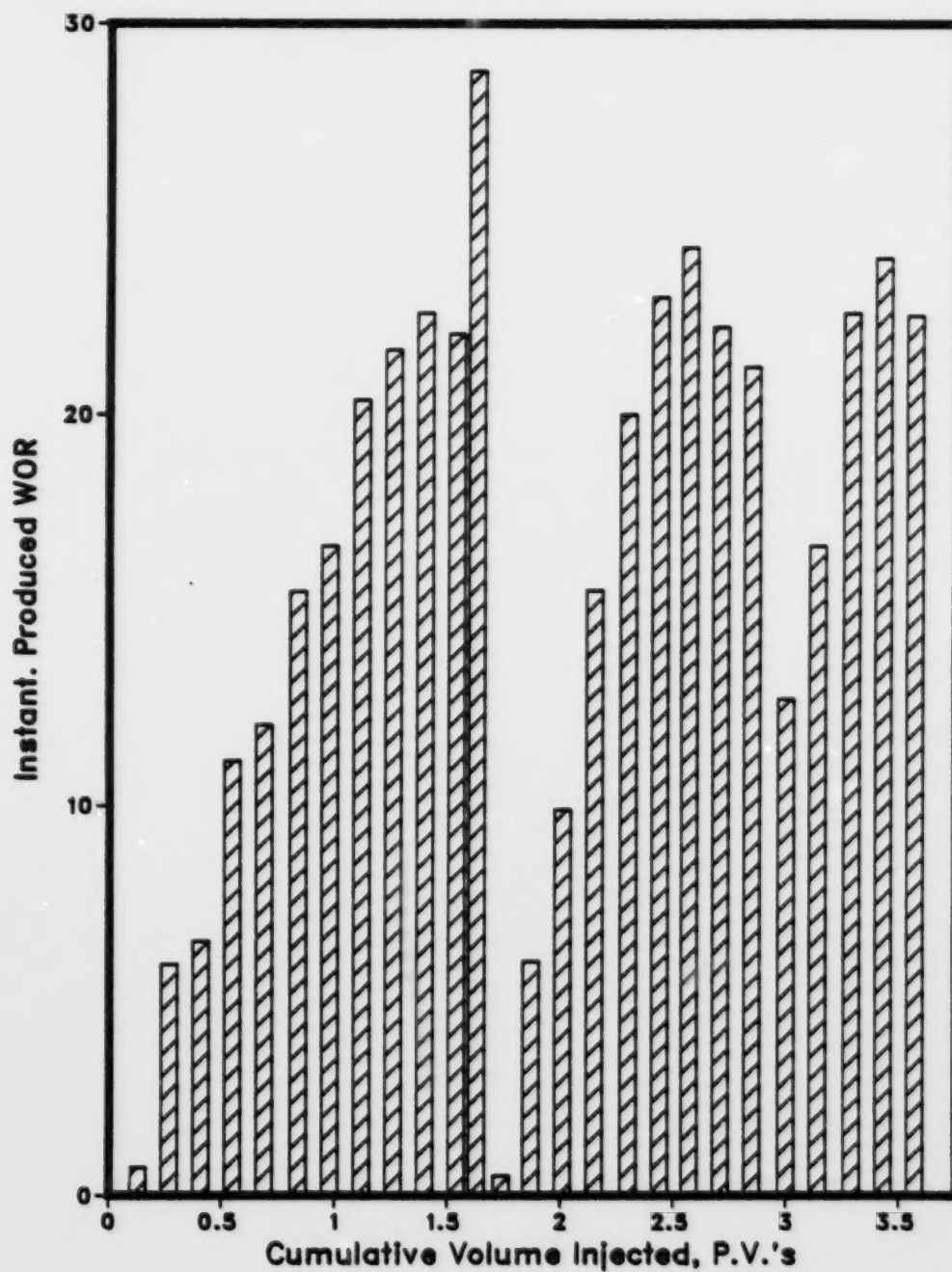
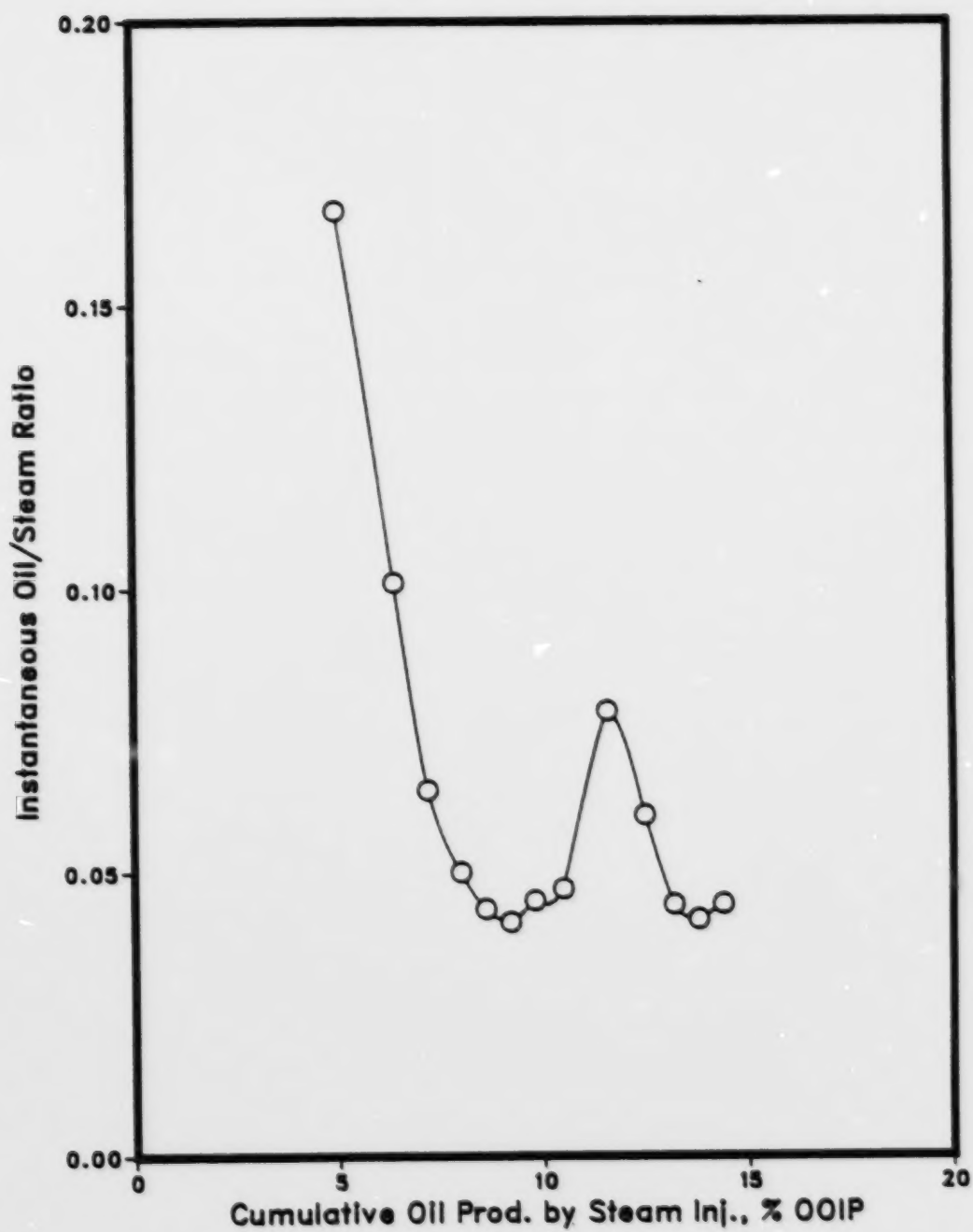


Figure 5.102 :Run 47 Waterflood Followed by Solvent-Steamflood
Instantaneous Oil/Steam Ratio Vs. Cumulative Oil Produced



volume injected for Runs 47 (Figures 5.100 & 5.101) and 48 (Figures 5.104 & 5.105) provide a good indication of when waterflooding and steamflooding were implemented and when water and steam breakthrough occurred during the experiments. Overlaying the bar plots on the respective recovery curves demonstrates how well the bar graphs correspond to the different stages of the runs such as water and steam breakthrough. Study of the water/oil ratio plots also revealed small peaks in the later stages of the steamflood which represent the eventual production of small pockets of oil in the model.

The plots of instantaneous oil/steam ratio versus cumulative oil produced shown in Figures 5.102 (Run 47) and 5.106 (Run 48) also confirm that steam breakthrough took place early in the continuous steamflood due to the high initial water saturation.

The top view temperature contours provided for Runs 47 (Fig. A.263-A.270) and 48 (Fig. A.274-A.281) demonstrate that during the waterflood and the solvent-steamflood the injected water, solvent and steam advanced slightly faster through the lower portion of the model. The cross-sectional temperature profiles for Runs 47 (Fig. A.271-A.273) and 48 (Fig. A.282-A.285) provided the profiles for both experiments after every 0.50 pore volumes injected once the solvent-steamflood had been initiated (ie. after waterflooding). The cross-sectional profiles for both runs indicated, as did the top view temperature profiles, the injected heat of the steam advanced faster through the lower portion of the model.

During the initial stages of the run an oil bank formed ahead of the water front resulting in an increased amount of oil being produced. Water breakthrough occurred at the production well once the oil bank had been produced and a subsequent drop in oil production resulted. When the desired WOR was attained, a 0.10 pore volume solvent slug was injected into the model which immediately began mixing with the immobile oil, reducing the oil viscosity. Initiation of continuous steam injection caused the oil/solvent mixture in the model to bank up ahead of the steam front. This resulted in additional oil production due to the recovery of the oil/solvent bank at the production well. Steam

breakthrough and a preceding slump in oil output took place after the larger portion of the oil/solvent bank had been produced. Following steam breakthrough, the high temperature steam continued to sweep through the model mobilizing more oil from both the swept and unswept zones.

Solvent recoveries for Runs 47 (44.9%) and 48 (58.9%) varied slightly but were still relatively similar. Comparing the solvent recoveries for these two runs to Runs 44 (70.4%) and 45 (71.2%), it is apparent that Runs 47 and 48 have much lower solvent recoveries. In Runs 44 and 45 the solvent was injected into a model that was oil saturated with a connate water saturation. However, in Runs 47 and 48 the solvent was injected into the model after it had been waterflooded, and therefore the initial water saturation was much higher and a residual oil saturation existed.

As was discussed in the previous section dealing with the solvent recovery, results for Runs 47 and 48 were consistent with Alikhan ⁶⁴'s findings. He stated that a solvent-steamflood process implemented in an oil saturated model yielded a greater solvent recovery than when performed in a waterflooded model. The nature of the solvent recovery in these two instances could be related to increased mixing of solvent with oil in the waterflooded situation which caused more solvent to remain in the model as a residual hydrocarbon saturation. The varying degree of oil-solvent mixing in the two different types of runs may be a result of the solvent having a higher relative permeability in the oil saturated experiments than the waterflooded cases. The higher relative permeability would create more distinct solvent channelling and less mixing with the in-place oil, and hence a larger solvent recovery. For the waterflooded situation, the difference in relative permeability between the water and the solvent would be less than for the oil saturated case due to the higher initial water saturation. The solvent would not flow through the model as easily thus blending more thoroughly with the in-place oil. Mixing of solvent and oil would be more pronounced in the waterflooded case. This would decrease the amount solvent recovered due to the remainder of a higher residual solvent slug material saturation. The

difference in the solvent recoveries in the two runs may also be due to changes in interfacial tension when solvent mixes with the in-place oil.

The overall oil recoveries for Runs 47 (33.5% OOIP) and 48 (35.5% OOIP) were higher than the recoveries obtained from the conventional steamfloods of the homogeneous model performed in Runs 26 (31.8% OOIP) and 27 (32.2% OOIP) as reported by Proctor, George and Farouq Ali ⁶³. The recoveries for the solvent-steamfloods of a homogeneous model (Runs 44 (27.1% OOIP), 45 (30.0% OOIP) & 46 (27.7% OOIP)) reported in this study also indicate that Runs 47 and 48 yielded a greater overall oil recovery. The oil recoveries for the waterflood cases (Runs 47 & 48) were higher because the solvent was able to blend with inplace oil more thoroughly than during the oil saturated experiments (Runs 26, 27, 44, 45 & 46). Alikhan also stated that for a high initial oil saturation the solvent slug is displaced as efficiently as the in-place oil, thus the advantage of using the solvent is partially lost and the oil recovery is diminished. However, for a waterflooded porous media the solvent is able to mix more extensively with the oil allowing the injected steam to contact a higher saturation of the solvent slug material leading to improved oil recovery.

Comparing the oil recovery for Runs 47 and 48 with those for the previous experiments using a homogeneous model and Faxam-100, it was noted that Runs 47 and 48 supplied the highest oil recovery of all the experiments performed using a homogeneous model saturated with Faxam-100 oil which includes the steamfloods reported by Proctor, George and Farouq Ali ⁶³ (Runs 26 & 27) and the solvent-steamfloods conducted in this research (Runs 44, 45 & 46). The information obtained from Runs 47 and 48 agrees closely with the results recorded by Alikhan ⁶⁴. Performing solvent-steamfloods on waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery technique.

Table 5.26 : Run 48A Waterflood Prior to Solvent-Steamflood of Homogeneous Model

HC Pore Volume :	13000.0 cc	Type of Oil Used :	Faxam-100
Pore Volume :	14030.0 cc	Initial Model Temperature :	3.00 C
Bulk Volume :	42005.0 cc	Water Feed Flow Rate :	200.00 cc/min
Porosity :	33.4%	Initial Oil Saturation :	92.7%
		Initial Water Saturation :	7.3%

Net Oil Recovery : 19.8%

Final Oil Saturation : 74.3%

Cylinder No.	Tot. Vol. Inj. (cc)	Cum. Vol. Inj. (cc)	Cum. Vol. Inj. (P.V.)	Oil Prod. (cc)	Cum. Oil Rec. (cc)	Cum. Oil Rec. (%OOIP)	Inst. Prod. WOR	Inst. Oil Prod. % of Sample
1	2030.0	2030.0	0.14	1035.0	1035.0	8.0%	0.96	51.0%
2	2020.0	4050.0	0.29	320.0	1355.0	10.4%	5.31	15.8%
3	1865.0	5915.0	0.42	240.0	1595.0	12.3%	6.77	12.9%
4	2000.0	7915.0	0.56	165.0	1760.0	13.5%	11.12	8.3%
5	1870.0	9785.0	0.70	135.0	1895.0	14.6%	12.85	7.2%
6	1985.0	11770.0	0.84	110.0	2005.0	15.4%	17.05	5.5%
7	1885.0	13655.0	0.97	105.0	2110.0	16.2%	16.95	5.6%
8	2040.0	15695.0	1.12	100.0	2210.0	17.0%	19.40	4.9%
9	2045.0	17740.0	1.26	95.0	2305.0	17.7%	20.53	4.6%
10	1980.0	19720.0	1.41	90.0	2395.0	18.4%	21.00	4.5%
11	1935.0	21655.0	1.54	90.0	2485.0	19.1%	20.50	4.7%
12	2085.0	23740.0	1.69	85.0	2570.0	19.8%	23.53	4.1%

Table 5.27 : Run 48B Solvent-Steamflood Following a Waterflood of Homogeneous Model

HC Pore Volume : 10430.0 cc				Type of Oil Used : Faxam-100								
Pore Volume : 14030.0 cc				Initial Model Temperature : 3.00 C								
Bulk Volume : 42005.0 cc				Water Feed Flow Rate : 200.00 cc/min								
Porosity : 33.4%				Boiler Feed Flow Rate : 29.20 cc/min								
Initial Oil Satn. : 74.3%				Total Flow Rate of Steam : 229.20 cc/min								
Initial H2O Satn. : 25.7%				Solvent Flow Rate : 200.00 cc/min								
Solvent Vol. Inj.: 1400.0 cc (10.0% PV)				Steam Vol. Injected : 30235 cc (2.16 PV)								
Net Oil Recovery : 35.5%				Solvent Recovery : 58.9%				Final Oil Saturation : 59.8%				
Cyl. No.	Solvent Conc. (%)	Tot. Vol. Inj.		HC Prod. (cc)	Oil Prod. (cc)		Cum. Oil Rec.		Cum. Sol. Rec. (cc)	Oil-Solvent Ratio	Inst Prod. WOR	Inst. HC Prod. % of Sample
		Inj. (cc)	Cum. Vol. Inj. (cc)		(cc)	(%OOIP)	(cc)	(%)				
1	6%	1120	1340	30	28	28	0.2%	2	0.1%	0.0000	36.33	2.7%
2	58%	1940	3280	1195	502	530	4.1%	695	49.6%	0.0000	0.62	61.6%
3	25%	1900	5180	315	236	766	5.9%	774	55.3%	0.1987	5.03	16.6%
4	13%	2090	7270	180	157	923	7.1%	797	56.9%	0.0942	10.61	8.6%
5	8%	1960	9230	80	74	997	7.7%	803	57.4%	0.0426	23.50	4.1%
6	6%	2105	11335	100	94	1091	8.4%	809	57.8%	0.0499	20.05	4.8%
7	4%	1940	13275	80	77	1168	9.0%	812	58.0%	0.0430	23.25	4.1%
8	5%	2015	15290	150	143	1311	10.1%	819	58.5%	0.0804	12.43	7.4%
9	3%	1975	17265	95	92	1403	10.8%	822	58.7%	0.0505	19.79	4.8%
10	2%	2095	19360	95	93	1496	11.5%	824	58.9%	0.0475	21.05	4.5%
11	0%	2045	21405	50	50	1546	11.9%	824	58.9%	0.0251	39.90	2.4%
12	0%	2180	23585	100	100	1646	12.7%	824	58.9%	0.0481	20.80	4.6%
13	0%	1960	25545	110	110	1756	13.5%	824	58.9%	0.0595	16.82	5.6%
14	0%	2030	27575	100	100	1856	14.3%	824	58.9%	0.0518	19.30	4.9%
15	0%	1975	29550	95	95	1951	15.0%	824	58.9%	0.0505	19.79	4.8%
16	0%	2085	31635	95	95	2046	15.7%	824	58.9%	0.0477	20.95	4.6%

Figure 5.103 Run 48 Waterflood Followed By Solvent-Steamflood
Cumulative Oil Recovery Vs. Pore Volumes Injected

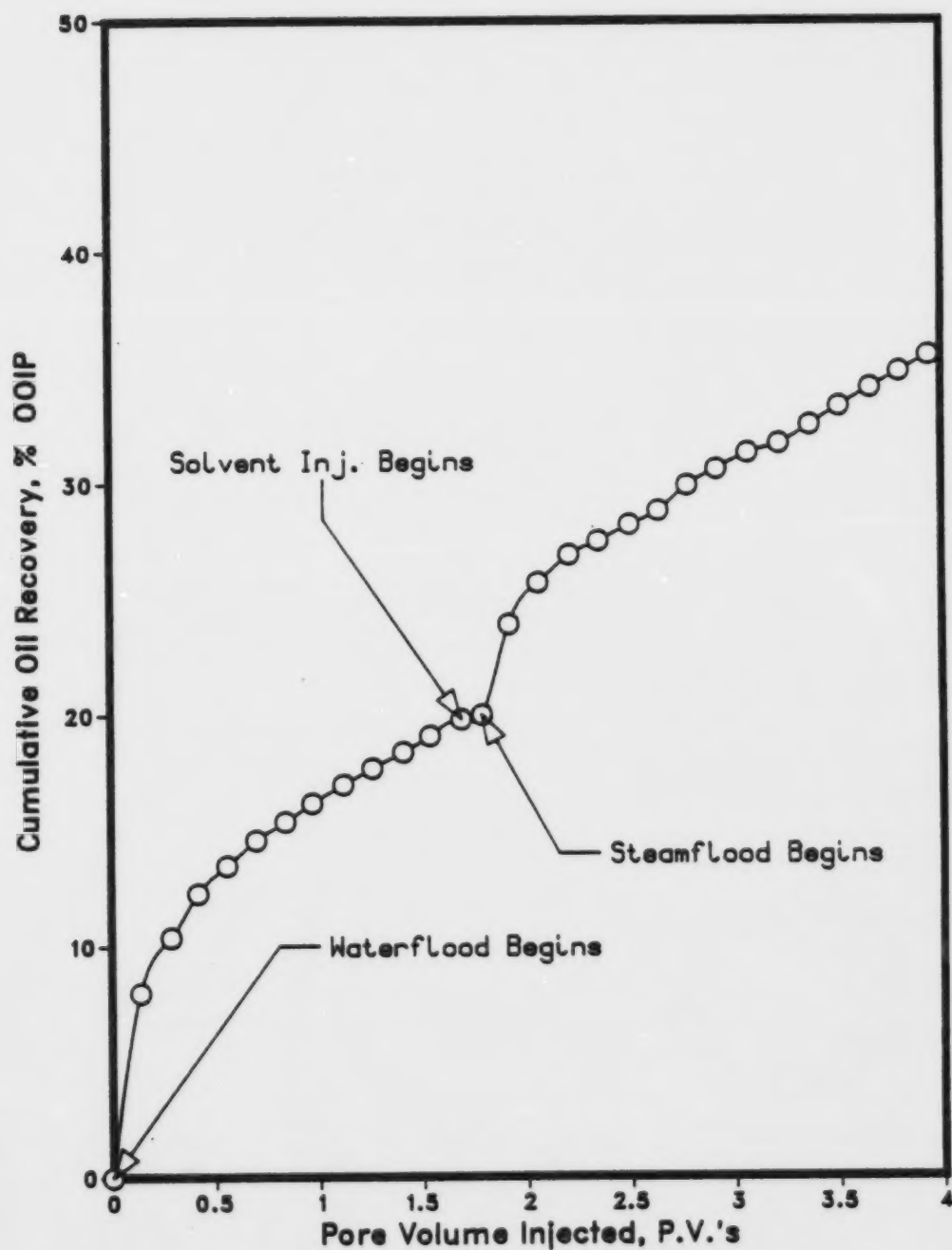


**Figure 5.104 :Run 48 Waterflood Followed By Solvent-Steamflood
Oleic Phase In Each Sample Vs. Cumulative Volume Injected**

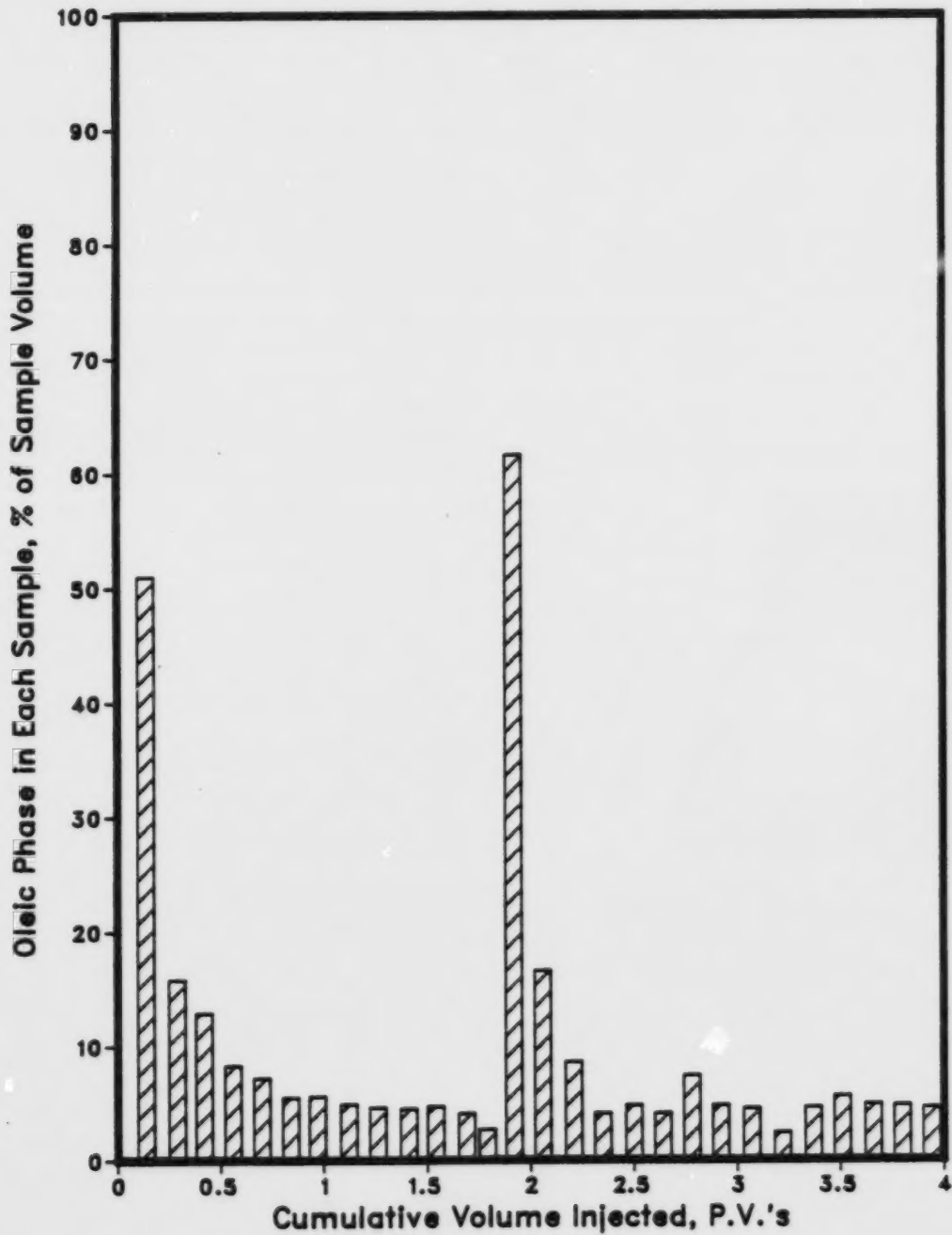


**Figure 5.10⁵ :Run 48 Waterflood Followed By Solvent-Steamflood
Instantaneous Produced WOR Vs. Cumulative Volume Injected**

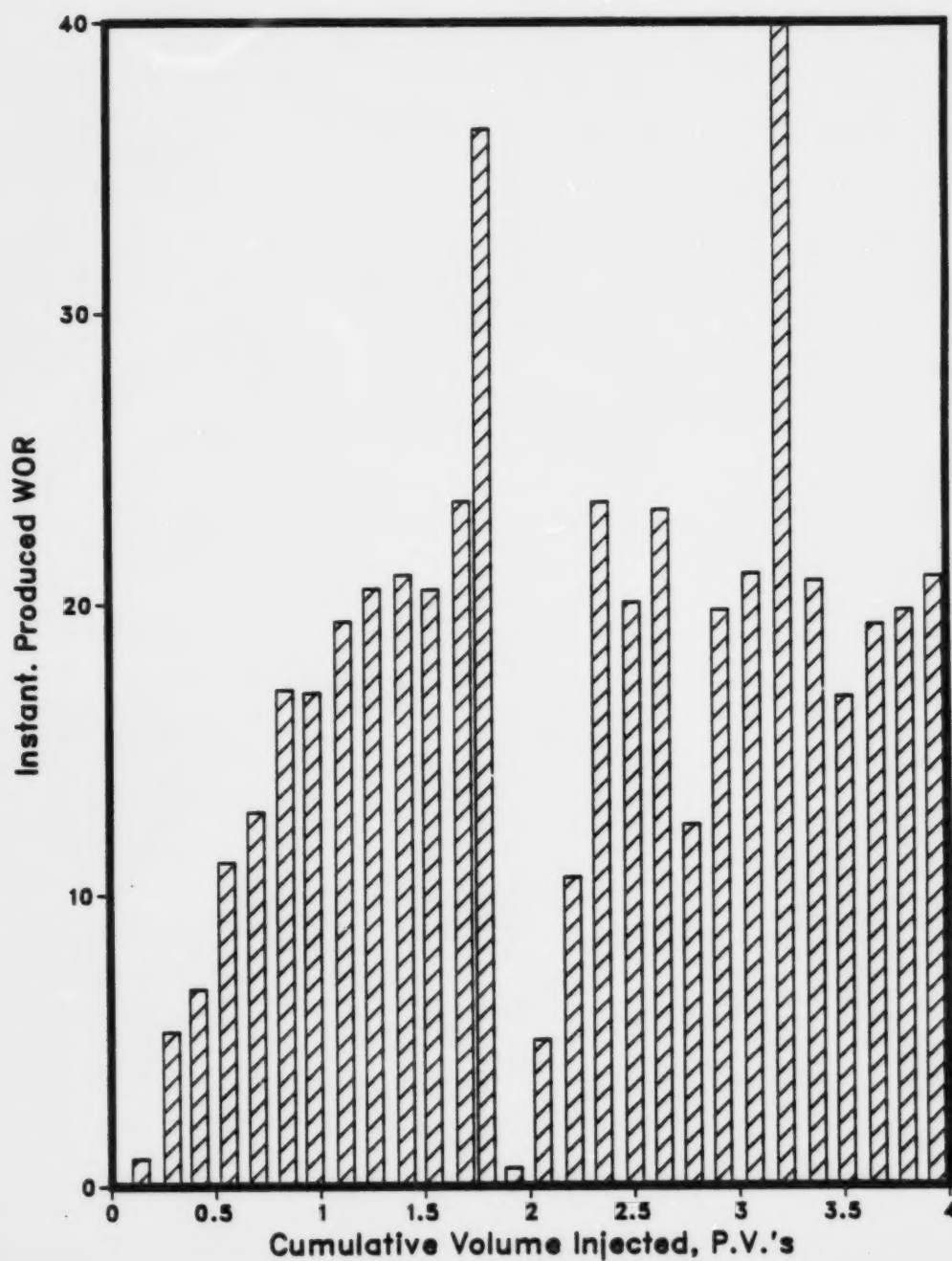
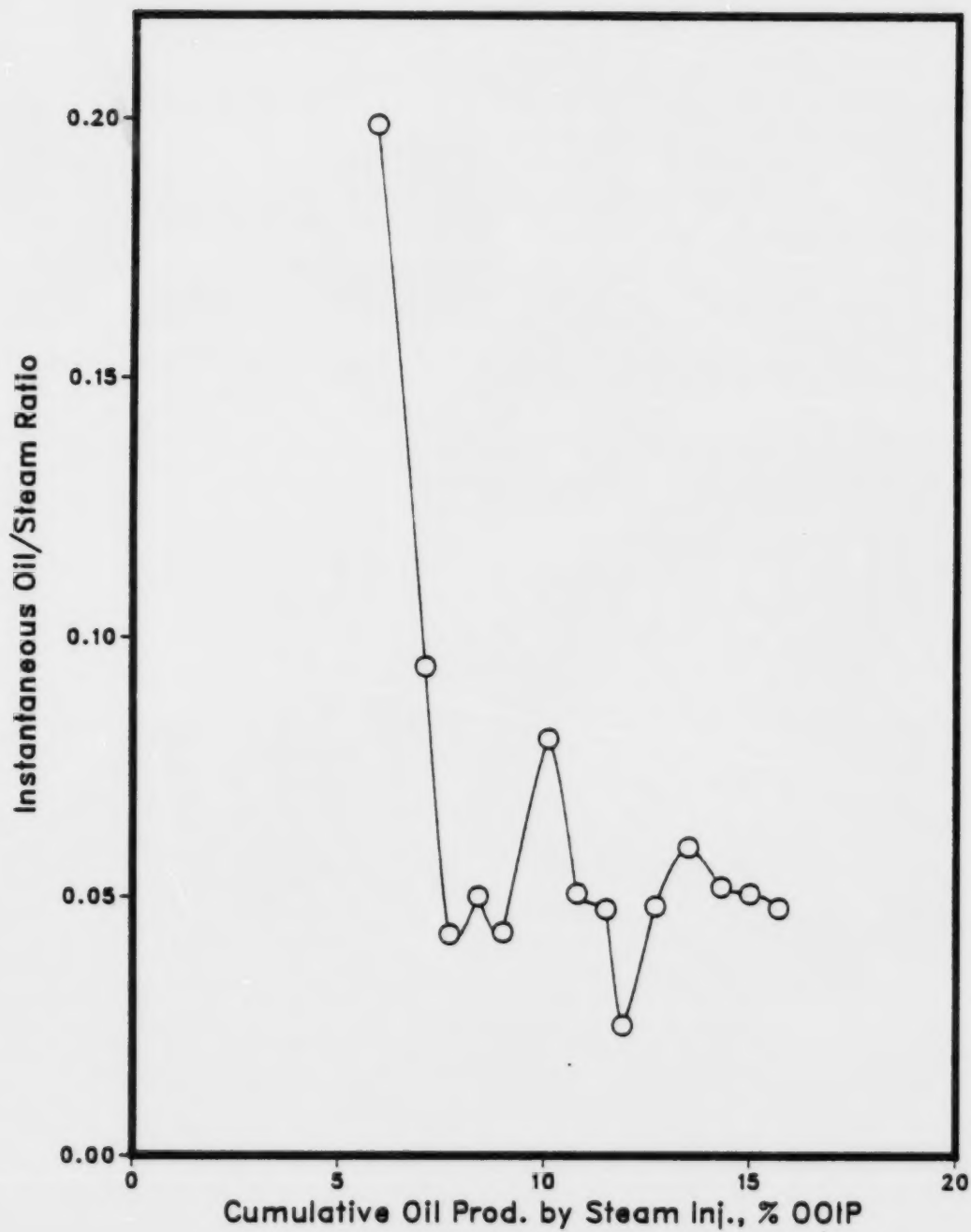


Figure 5.106 :Run 48 Waterflood Followed by Solvent-Steamflood
Instantaneous Oil/Steam Ratio vs. Cumulative Oil Produced



Heat Flow Analysis

The objective of this analysis was to obtain an understanding of the heat transfer occurring in the low pressure model during an experiment. In order to simplify the analysis a base steamflood (Run 26) experiment was used in the study.

Lauwerier Equation

The first stage of the analysis involved comparing the temperature contours constructed for Run 26 (Fig. A.286-A.292) with results obtained by applying the Lauwerier equation to the temperature profiles. The purpose of this comparison was to observe if the injection process in the model more closely represented a hot waterflood as opposed to the desired steamflood.

The Lauwerier equation represents formation heating by hot fluid injection which does not possess latent heat of vaporization. If hot water is injected into a formation, a well-defined temperature distribution is established in the porous medium. Since hot water is the injected fluid the heating in the formation is due to sensible heat content and not the latent heat as is the case in steam injection. According to Lauwerier, the temperature at any particular time at the injection point is the same as the temperature of the injected fluid. The temperature in the reservoir decreases steadily with distance, eventually approaching the initial reservoir temperature (T_R) as one moves away from the injection point. As greater amounts of the hot fluid are introduced the temperature at each point in the formation increases until the injected fluid temperature is reached at the infinite time.

As derived by Lauwerier⁶⁸, the temperature (T) at any linear distance (x) or radial distance (r) from the injection point is given by the proceeding equation.

$$T = T_R + (T_F - T_R) \operatorname{erfc} \left[\frac{x_D}{2 \sqrt{t_D - x_D}} \right] \quad \text{for } t_D > x_D$$

$$T = T_R \quad \text{for } t_D \leq x_D$$

$$\text{Dimensionless distance } x_D = \frac{4 (24) k_{hob} M_{ob} A}{5.615 M_s \rho_w i_w h_t}$$

$$\text{Dimensionless time } t_D = \frac{4 k_{hob} M_{ob} A}{M_s^2} \cdot \frac{t}{h_t^2}$$

Where k_{hob} - thermal conductivity of overburden (BTU/hr-ft-°F)

M_{ob} - heat capacity of overburden (BTU/ft³-°F)

M_s - heat capacity of heated sand (BTU/ft³-°F)

t - time (hr)

h_t - gross thickness (ft)

ρ_w - density of injected fluid (lb/ft³)

c_w - specific heat of injected fluid (BTU/lb-°F)

A - area (ft²)

Where $A = bx$ or $A = \pi r^2$

b - width (ft) r - radial distance (ft)

x - linear distance (ft)

All of the temperature profiles for Run 26 consist of two sets of contours. One set represents the upper half of the model while the other contour describes the lower portion. A computer program was created which utilized the Lauwerier equation and the temperature contours for Run 26 (0.25 to 1.00 P.V.). The computer program is given on page 576 of Appendix B. The area (A) used in this study was defined as the area existing between a particular temperature contour and the injection point. The area covered by each corresponding temperature on each profile was measured by a planimeter and then substituted into the Lauwerier equation in order to obtain a estimated temperature related to the measured area.

From the analysis, Tables 5.28 and 5.29 were prepared, which list the portion of model being represented, the amount of fluid injected in pore volumes prior the specific contour, the actual contour line temperature used to measure the previously discussed area and the temperature yielded by the Lauwerier equation corresponding to the area.

In this analysis the model was divided to the upper and lower portion. The fluid injection rate used for each interval is an estimate only: in Table 5.28 it is assumed that each portion of the model received one half of the total injected fluid. However, the greater part of the injection interval for Run 26 was situated in the upper portion of the model. Therefore, in Table 5.29 it was assumed that three-quarters of the total fluid injected entered the upper zone of the model while the remaining one-quarter went into the bottom portion.

For Table 5.28, a comparison of the temperatures calculated for the upper and lower portions, using Lauwerier's equation, suggests that the upper part of the model was being heated faster than the lower portion. This indicates gravity override of the steam rather than the usual underriding of the formation by injected water. This is also evident in Table 5.29 but to a larger extent due to a higher injection rate in the upper region of the model. A steamflood occurs in the model since the upper portion heats up faster than the lower zone, which leads one to believe that steam override was present in the model.

Comparing the actual contour temperature to that obtained from the Lauwerier equation can also be useful in determining if steam existed in the model. The actual contour temperatures, which are at the approximate steam temperature of 70°C, are greater than the Lauwerier equation temperatures in the upper and lower portions of the model in both Tables 5.28 and 5.29. Since the actual temperature is greater than the assumed Lauwerier hot waterflood temperature, the existence of the steam in the model is evident. As well, the actual contour temperatures at 60°C are only slightly less than the Lauwerier equation temperatures which indicates that a hot water or condensate bank existed ahead of the steam zone. The lower actual contour temperatures, compared to the Lauwerier equation, are for the most part considerably less which indicates the heating and subsequent displacement of in-place oil ahead of the steam and hot water regions. At the lowest actual contour temperatures the Lauwerier equation temperatures are equal to or approach the initial

reservoir temperature meaning that the oil in this region of the model has not been affected by the advancing hot water and steam zones at this point in time.

From the comparison of the actual and calculated temperatures as well as the indication of gravity overriding by the injected fluid, it is concluded that steam was present in the model throughout Run 26. Also a hot water or condensate region is believed to form ahead of the steam front.

Comparison of Marx-Langenheim and Mandl-Volek Models

A. Marx-Langenheim Theory

The second portion of the heat flow analysis consisted of a comparison of the Marx-Langenheim⁵ and Mandl-Volek⁶⁹ models of formation heating by steam injection for the low pressure model in Run 26. Both steam injection theories give the steam zone volume at any point in time during a steam injection process.

According to Marx-Langenheim theory, when steam is introduced into an oil bearing formation at an initial reservoir temperature (T_R), a certain amount of oil is displaced by the steam. At the same time the injected steam condenses and heats the reservoir rock and fluids. The hot water region formed ahead of the steam, which is assumed to be at the steam temperature (T_S), preheats the reservoir ahead of the steam. The Marx-Langenheim theory assumes idealized conditions, and therefore the heated zone is at a constant temperature (T_S) which extends from the injection end to a point where the temperature sharply drops from T_S to T_R . For this to occur Marx-Langenheim theory assumes no gravity segregation of steam, uniform thickness, injection over entire thickness at a constant rate and no temperature drop in the steam zone.

Figure 5.107 shows a schematic representation of the idealized temperature and steam quality distributions for the Marx-Langenheim model of reservoir heating by steam injection. The steam zone or heated region represents the volume of fluids and rocks heated to steam temperature (T_S), regardless of the steam quality. Marx-Langenheim

theory assumes that the condensate transfers the sensible heat over an infinitesimal distance which constitutes the condensate front.

Marx and Langenheim developed an equation to calculate the steam zone volume (V_S), which is as follows:

$$V_S = \frac{Q_i M_s h_i^2 F_1}{4 k_{ob} M_{ob} (T_s - T_R)}$$

$$\text{Where } Q_i = \left(\frac{350}{24} \right) i_s \{ h_w - h_R + f_{st} L_v \}$$

Q_i - heat injection rate (BTU/hr)

i_s - steam injection rate (B/D - water equivalent)

h_w - saturated water enthalpy (BTU/lb)

h_R - enthalpy of water at reservoir temperature, T_R (BTU/lb)

f_{st} - steam quality

L_v - latent heat of vaporization for the steam (BTU/lb)

F_1 is a function of the dimensionless time, t_D .

$$F_1 = e^{t_D} \operatorname{erfc} \sqrt{t_D} + 2 \sqrt{t_D/\pi} - 1 \quad \text{or} \quad F_1 \cong \frac{t_D}{1 + 0.85 \sqrt{t_D}}$$

B. Mandl-Volek Theory

The major weakness of the Marx-Langenheim model, apart from neglecting gravity effects is that the injected steam continues to furnish the latent heat contained in the newly invaded strata as well as supplying heat for heat loss to adjacent formations. As long as the latent heat injection rate is greater than its consumption rate the Marx-Langenheim model is valid. However, at a particular time, called "critical time" by Mandl and Volek, this ceases to occur, and therefore an allowance must be made for convective heat transport by hot water ahead of the condensation front.

In the Mandl-Volek model, as long as the time is less than critical time, Marx-Langenheim theory can be implemented. If the time is greater than the critical time then the Mandl-Volek theory applies.

Estimation of the steam zone volume by the Mandl-Volek model is the average for two boundary conditions which are analytically solved. The first condition assumes no hot water movement in front of the condensation zone and therefore is the same as the Marx-Langenheim solution. The second condition assumes hot water movement and heat loss ahead of the front with no preheating of the overburden at the front.

Therefore the steam zone volume is calculated as shown below.

$$V_s = \frac{Q_i h_i^2}{(T_s - T_R)} \cdot \frac{M_s F_1}{4 k_{hob} M_{ob}} \quad \text{for } t \leq t_c \quad (\text{Marx-Langenheim})$$

$$V_s = \frac{Q_i h_i^2}{(T_s - T_R)} \cdot \frac{M_s F_3}{4 k_{hob} M_{ob}} \quad \text{for } t > t_c \quad (\text{Mandl-Volek})$$

$$\text{Where } F_3 = e^{t_D} \operatorname{erfc} \sqrt{t_D} + 2 \sqrt{\frac{t_D}{\pi}} - 1 - \sqrt{\frac{t_D - t_{DC}}{\pi}} \\ \left\{ \left[1 + \frac{f_{st} L_v}{c_w (T_s - T_R)} \right]^{-1} + \left(\frac{t_D - t_{DC} - 3}{3} \right) e^{t_D} \operatorname{erfc} \sqrt{t_D} - \frac{t_D - t_{DC}}{3 \sqrt{\pi t_D}} \right\}$$

Two computer programs were developed, which calculate the steam zone volume after every quarter of a pore volume of steam injected for experiment 26. The first program (page 578, Appendix B) incorporate the Marx-Langenheim solution to determine the steam zone volume. The second program (page 580, Appendix B) utilizes the Mandl-Volek theory for steam zone volume calculation.

Results of the comparison of the Marx-Langenheim and Mandl-Volek models are shown in Table 5.30. The table lists estimated steam zone volumes for both the Marx-Langenheim and Mandl-Volek situations at every quarter of a pore volume of steam injected for Run 26.

The results listed in Table 5.30 indicate that the steam zone volume calculated using the Marx-Langenheim theory was approximately 20% greater than the volume estimated using the Mandl-Volek theory. After two pore volumes of steam had been injected the predicted steam zone volume according to Marx-Langenheim theory was 65.55 % of the

model's bulk volume, while the Mandl-Volek model estimated the steam zone volume to be 50.58 % of the model bulk volume. A comparison of the results of the two models indicates the critical time was reached soon after steam injection was initiated, therefore the Mandl-Volek model provided a better representation of the steam injection process which occurred in the low pressure model. It is also implied that the latent heat injection rate was less than the consumption rate of the injected heat.

From the results it was concluded that the Mandl-Volek model provides the more accurate representation of the steam zone developement in the model, which suggests that the latent heat injection rate was less than its consumption rate.

Heat Loss Analysis

A heat balance was performed on Run 26 to determine the total heat injected total heat remaining in the model and the total heat lost from within the model. The equations used for the heat balance were obtained from Farouq Ali's ⁷⁰ text on heavy oil recovery.

Therefore the heat balance for Run 26 according to Farouq Ali ⁷⁰ is as follows.

$$\begin{array}{lclcl} \text{Total Amount} & = & \text{Total Heat Lost to the} & + & \text{Total Heat Existing} \\ \text{of Heat Injected} & & \text{Surroundings and} & & \text{in the Low Pressure} \\ \text{in the Model} & & \text{the Produced Fluids} & & \text{Model} \end{array}$$

$$\text{or } Q_i(t) = Q_{ob} + Q_s$$

$$\text{Where } Q_i(t) = \left(\frac{350}{24} \right) i_s \{ h_w - h_R + f_{st} L_v \} t$$

$Q_i(t)$ - total amount of heat injected (BTU)

i_s - steam injection rate (B/D - water equivalent)

h_w - saturated water enthalpy (BTU/lb)

h_R - enthalpy of water at reservoir temperature, T_R (BTU/lb)

f_{st} - steam quality

L_v - latent heat of vaporization for the steam (BTU/lb)

t - time (hr)

Determination of the total heat lost from the model (Q_{ob}) involved calculating the volume that each contour temperature occupied in the upper and lower temperature profiles

for Run 26 (Fig. A.286-A.292). The volumes were calculated by measuring the area encompassed by each contour line for the upper and lower sections of the model. The area measured using a planimeter was then multiplied by one half the thickness of the model since the model was divided into upper and lower portions, each being half the thickness of the entire model. This calculation yielded the volume which each specific temperature contour occupied in the model.

The heat content of each elemental volume was determined using the following equation.

$$H_i = M_s V_i (T_i - T_R)$$

Where

H_i - heat content of volume i (BTU)

M_s - heat capacity of heated model

V_i - volume of element i (ft³)

T_i - temperature of element i (°F)

T_R - initial model temperature (°F)

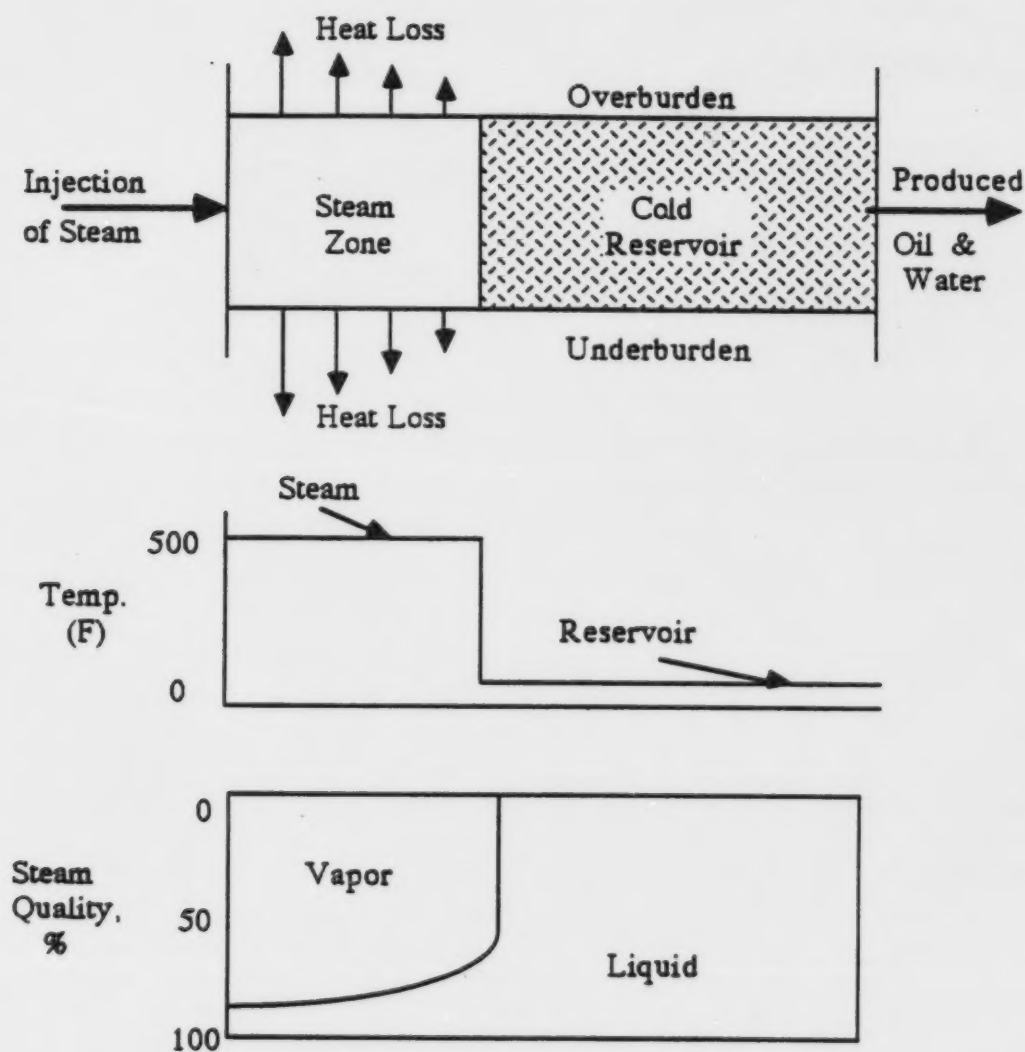
The total heat existing in the model (Q_s) was then determined by summing the heat contained in each elemental volume, i .

$$Q_s = \sum_{i=1}^n H_i$$

Since values for $Q_i(t)$ and Q_s were obtained, a value for the total heat lost from the model (Q_{ob}) during experiment 26 could be predicted using the previously described heat balance equation.

Values of $Q_i(t)$, Q_s and Q_{ob} are listed respectively in Table 5.31 for every one quarter of a pore volume of steam injected into the model during Run 26. Total heat injected was given in BTU's while the heat lost and the heat remaining were listed as a percentage of the total heat injected into the model. A computer program (page 582, Appendix B) was developed which calculates the total heat injected into the model, the amount of heat contained in the model and the amount of heat lost from the model in Run 26, which was a base steamflood.

Results of the heat balance analysis in Table 5.31 reveal that heat loss from the model was considerable, and that approximately one-quarter of the total heat injected into the model remained in the model. Therefore about 75 % of the total heat injected was lost to the surroundings and the produced fluids. The magnitude of this heat loss is typical of steam injection processes in thin reservoirs. It was also noted from the results that the heat loss rate from the model was reasonably constant throughout the experiment.



Key Assumptions

- * No Gravity Effects
 - Entire Thickness Heated to Steam Temperature
 - No Hot Water Flow Ahead of Condensation Front
- * Homogeneous Sands and Shale
- * No Pressure Drop
- * Constant Injection Rate

Figure 5.107 : Schematic Diagram of the Marx-Langenheim model for reservoir heating by steam injection.

Table 5.28 : Heat Flow Analysis of Model Using The Lauwerier Equation
(Experiment 26)

Portion of Model	Pore Volume Injected	Actual Contour Temp. (C)	Lauwerier Equation Temp. (C)	Portion of Model	Pore Volume Injected	Actual Contour Temp. (C)	Lauwerier Equation Temp. (C)
Upper	0.25	10	15.17	Upper	0.75	10	3.00
Inj. Rate		20	41.08	Inj. Rate		20	36.41
1.0270 B/D		30	55.49	1.0270 B/D		30	54.53
		40	59.74			40	61.94
		50	63.45			50	64.51
	0.25	60	65.84		0.75	60	66.39
		70	67.15			70	67.62
Lower		10	3.00	Lower		10	3.00
Inj. Rate		20	11.15	Inj. Rate		20	3.00
1.0270 B/D		30	49.61	1.0270 B/D		30	4.91
	0.50	40	57.85		1.00	40	15.78
		50	62.37			50	33.72
		60	65.58			60	57.11
		70	66.82			70	65.83
Upper		10	16.33	Upper		10	3.00
Inj. Rate	0.50	20	39.50	Inj. Rate	1.00	20	25.29
1.0270 B/D		30	52.99	1.0270 B/D		30	49.45
		40	59.12			40	61.08
		50	61.08			50	63.48
		60	63.53			60	65.34
	0.50	70	65.07			70	67.02
Lower		10	3.00	Lower	1.00	10	3.00
Inj. Rate		20	3.00	Inj. Rate		20	3.00
1.0270 B/D		30	4.58	1.0270 B/D		30	3.00
		40	16.88			40	6.50
		50	34.71			50	18.49
	0.50	60	58.54			60	36.31
		70	67.52			70	55.79

Table 5.29 : Heat Flow Analysis of Model Using The Lauwerier Equation
(Experiment 26)

Portion of Model	Pore Volume Injected	Actual Contour Temp. (C)	Lauwerier Equation Temp. (C)	Portion of Model	Pore Volume Injected	Actual Contour Temp. (C)	Lauwerier Equation Temp. (C)
Upper	0.25	10	32.61	Upper	0.75	10	4.32
Inj. Rate		20	50.65	Inj. Rate		20	47.02
1.5405 B/D		30	59.88	1.5405 B/D		30	59.16
		40	62.63			40	64.04
		50	65.05			50	65.74
		60	66.63			60	66.99
		70	67.49			70	67.80
Lower	0.25	10	3.00	Lower	0.75	10	3.00
Inj. Rate		20	3.00	Inj. Rate		20	3.00
0.5135 B/D		30	29.19	0.5135 B/D		30	3.00
		40	46.59			40	3.00
		50	56.24			50	8.68
		60	62.92			60	45.69
		70	65.45			70	63.46
Upper	0.50	10	32.15	Upper	1.00	10	3.00
Inj. Rate		20	49.30	Inj. Rate		20	38.74
1.5405 B/D		30	58.19	1.5405 B/D		30	55.78
		40	62.20			40	63.47
		50	63.48			50	65.06
		60	65.09			60	66.29
		70	66.11			70	67.40
Lower	0.50	10	3.00	Lower	1.00	10	3.00
Inj. Rate		20	3.00	Inj. Rate		20	3.00
0.5135 B/D		30	3.00	0.5135 B/D		30	3.00
		40	3.00			40	3.00
		50	8.53			50	3.10
		60	48.44			60	11.81
		70	66.86			70	43.18

Table 5.30 : Comparison of Marx-Langenheim & Mandl-Volek Models of Formation Heating by Steam Injection For the Low Pressure Model in Run 26

Pore Volumes of Steam Injected into the Model (P.V.)	Steam Zone Volume Using Marx-Langenheim Theory (% of Model's Bulk Volume)	Steam Zone Volume Using Mandl-Volek Theory (% of Model's Bulk Volume)
0.25	16.21	14.43
0.50	26.62	22.25
0.75	35.05	28.44
1.00	42.35	33.76
1.25	48.89	38.51
1.50	54.85	42.83
1.75	60.38	46.84
2.00	65.55	50.58

**Table 5.31 : Analysis of Heat Loss Occurring During a Base Steamflood
(Experiment 26)**

Pore Volumes of Steam Injected into the Model (P.V.)	Total Amount of Heat Injected into the Model (Btu's)	Heat Remaining in the Model (% of Total Heat Injected)	Heat Lost to Surroundings & Produced Fluids (% of Total Heat Injected)
0.25	1438.74	24.45%	75.55%
0.50	2877.47	29.17%	70.83%
0.75	4316.21	20.61%	79.39%
1.00	5754.94	36.60%	63.40%
1.25	7193.68	29.60%	70.40%
1.50	8632.41	26.02%	73.98%
1.75	10071.15	27.14%	72.86%

Effect of Vertical/Horizontal Well Combinations

The final task of this research period was to conduct unscaled horizontal well experiments in the low pressure model in order to determine the dominant mechanisms and necessary parameters which will be used to scale horizontal wells.

The experiments were conducted using four vertical/horizontal well combinations and 10% steam quality. The purpose of these runs was to determine which of the combinations yielded the best oil recovery and to examine the effect of steam quality on recovery; previous horizontal well runs in Phase II were conducted with 1% quality steam. The steam injection experiments were performed in a homogeneous model using a vertical injector and horizontal producer, a horizontal injector and horizontal producer, a horizontal injector and vertical producer and a vertical injector and vertical producer and are respectively referred to as Runs 74, 75, 76 and 77, and are shown in detail in Tables 5.32 through 5.35.

As shown in Figures 5.108 and 5.109, the horizontal well injector and producer combination in Run 75 yielded the largest instantaneous and cumulative oil recovery as expected. However, Run 74, vertical injector and horizontal producer which is often selected by industry, had the lowest recovery. Since the laboratory results contradict field data, it was decided to concentrate future studies on the well combination used in Run 74 to determine the reason behind the low recovery value and hence, determine the optimum vertical-horizontal well combination for a marginal heavy oil reservoir. It is worthwhile to note that the steamflood recovery from Run 77 using 10% quality steam (field value is 60% OOIP recovery), 57.40% (%OOIP) at 2.14 PV injected, is substantially higher than one using 1% quality steam as was the case in Run 10 (Phase II) which recovered 31.48% (%OOIP) at 2.11 PV injected.

Table 5.32 Run 74: Steam injection of a homogeneous model using a vertical injector and horizontal producer.

HC Pore Volume:	12260 cc	Type of Oil Used:	Faxam-100
Pore Volume:	13460 cc	Initial Model Temperature:	3.5 C
Bulk Volume:	42005 cc	Total Flow Rate of Steam:	226.50 cc/min
Porosity:	32.0%	Steam Quality, fst:	0.14
Initial Oil Saturation:	91.1%	Total Steam Volume Injected:	29887 cc (2.21 PV)
Initial Water Saturation:	8.9%		

Net Oil Recovery: 50.16% Final Oil Saturation: 45.39%

Cylinder No.	Total Vol. Produced (cc)	Instantaneous Oil Prod. (cc)	Cumulative Oil Recovery (cc)	Cum. Oil Rec. %OOIP	Instantaneous Produced WOR	% Sample Vol. Oleic Phase	Cum. PV Injected
1	2090	910	910	7.4%	1.3	43.5%	0.16
2	1720	530	1440	11.7%	2.2	30.8%	0.24
3	1860	590	2030	16.6%	2.2	31.7%	0.33
4	1820	530	2560	20.9%	2.4	29.1%	0.43
5	2090	510	3070	25.0%	3.1	24.4%	0.55
6	1780	540	3610	29.4%	2.3	30.3%	0.64
7	2010	370	3980	32.5%	4.4	18.4%	0.76
8	2180	300	4280	34.9%	6.3	13.8%	0.92
9	1920	260	4540	37.0%	6.4	13.5%	1.05
10	1760	220	4760	38.8%	7.0	12.5%	1.18
11	1880	220	4980	40.6%	7.5	11.7%	1.31
12	1750	190	5170	42.2%	8.2	10.9%	1.44
13	1950	200	5370	43.8%	8.8	10.3%	1.60
14	1860	200	5570	45.4%	8.3	10.8%	1.74
15	2100	200	5770	47.1%	9.5	9.5%	1.90
16	1800	170	5940	48.5%	9.6	9.4%	2.05
17	2030	210	6150	50.2%	8.7	10.3%	2.21

Table 5.33 Run 75. Steam injection of a homogeneous model using a horizontal injector and horizontal producer.

HC Pore Volume:		12990 cc	Type of Oil Used:		Faxam-100		
Pore Volume:		14200 cc	Initial Model Temperature:		3.5 C		
Bulk Volume:		42005 cc	Total Flow Rate of Steam:		297.7 cc/min		
Porosity:		33.8%	Steam Quality, fst:		0.15		
Initial Oil Saturation:		91.5%	Total Steam Volume Injected:		30068 cc (2.12 PV)		
Initial Water Saturation:		8.5%					
Net Oil Recovery:		60.89%	Final Oil Saturation:		35.77%		
Cylinder No.	Total Vol. Produced (cc)	Instantaneous Oil Prod. (cc)	Cumulative Oil Recovery (cc)	Cum. Oil Rec. %OOIP	Instantaneous Produced WOR	% Sample Vol. Oleic Phase	Cum. PV Injected
1	1990	1130	1130	8.7%	0.8	56.8%	0.17
2	1700	280	1410	10.9%	5.1	16.5%	0.27
3	2260	560	1970	15.2%	3.0	24.8%	0.38
4	1700	400	2370	18.2%	3.3	23.5%	0.46
5	1890	660	3030	23.3%	1.9	34.9%	0.57
6	1760	480	3510	27.0%	2.7	27.3%	0.67
7	1800	460	3970	30.6%	2.9	25.6%	0.78
8	1720	420	4390	33.8%	3.1	24.4%	0.88
9	2040	560	4950	38.1%	2.6	27.5%	1.01
10	1750	390	5340	41.1%	3.5	22.3%	1.12
11	1940	460	5800	44.6%	3.2	23.7%	1.25
12	1780	600	6400	49.3%	2.0	33.7%	1.38
13	2060	420	6820	52.5%	3.9	20.4%	1.52
14	1800	290	7110	54.7%	5.2	16.1%	1.66
15	2140	280	7390	56.9%	6.6	13.1%	1.76
16	1700	240	7630	58.7%	6.1	14.1%	1.96
17	2000	280	7910	60.9%	6.1	14.0%	2.12

Table 5.34 Run 76. Steam injection of a homogeneous model using a horizontal injector and vertical producer.

HC Pore Volume:			12910 cc	Type of Oil Used:			Faxam-100
Pore Volume:			14250 cc	Initial Model Temperature:			2.5 C
Bulk Volume:			42005 cc	Total Flow Rate of Steam:			227.28 cc/min
Porosity:			33.9%	Steam Quality, fst:			0.10
Initial Oil Saturation:			90.6%	Total Steam Volume Injected:			30796 cc (2.16 PV)
Initial Water Saturation:			9.4%				
Net Oil Recovery:			53.91%	Final Oil Saturation:			41.75%

Cylinder No.	Total Vol. Produced (cc)	Instantaneous Oil Prod. (cc)	Cumulative Oil Recovery (cc)	Cum. Oil Rec. %OOIP	Instantaneous Produced WOR	% Sample Vol. Oleic Phase	Cum. PV Injected
1	1970	600	600	4.6%	2.3	30.5%	0.18
2	1760	650	1250	9.7%	1.7	36.9%	0.25
3	2020	830	2080	16.1%	1.4	41.1%	0.34
4	1620	480	2560	19.8%	2.4	29.6%	0.43
5	2000	630	3190	24.7%	2.2	31.5%	0.72
6	2040	510	3700	28.7%	3.0	25.0%	0.68
7	1980	440	4140	32.1%	3.5	22.2%	0.81
8	1920	400	4540	35.2%	3.8	20.8%	0.95
9	2060	400	4940	38.3%	4.2	19.4%	1.08
10	1690	310	5250	40.7%	4.5	18.3%	1.21
11	2300	380	5630	43.6%	5.1	16.5%	1.39
12	1760	280	5910	45.8%	5.3	15.9%	1.52
13	1990	290	6200	48.0%	5.9	14.6%	1.69
14	1780	250	6450	50.0%	6.1	14.0%	1.83
15	2060	280	6730	52.1%	6.4	13.6%	2.00
16	1800	230	6960	53.9%	6.8	12.8%	2.16

Table 5.35 Run 77. Steam injection of a homogeneous model using a vertical injector and vertical producer.

HC Pore Volume:		12560 cc	Type of Oil Used:		Faxam-100		
Pore Volume:		13620 cc	Initial Model Temperature:		1.5 C		
Bulk Volume:		42005 cc	Total Flow Rate of Steam:		227.28 cc/min		
Porosity:		32.4%	Steam Quality, fst:		0.10		
Initial Oil Saturation:		92.2%	Total Steam Volume Injected:		30910 cc (2.27 PV)		
Initial Water Saturation:		7.8%					
Net Oil Recovery:		58.76 %	Final Oil Saturation:		38.03 %		
Cylinder No.	Total Vol. Produced (cc)	Instantaneous Oil Prod. (cc)	Cumulative Oil Recovery (cc)	Cum. Oil Rec. %OOIP	Instantaneous Produced WOR	% Sample Vol. Oleic Phase	Cum. PV Injected
1	1340	450	450	3.6%	2.0	33.6%	0.18
2	2120	670	1120	8.9%	2.2	31.6%	0.27
3	1695	415	1535	12.2%	3.1	24.5%	0.35
4	1840	480	2015	16.0%	2.8	26.1%	0.45
5	1960	570	2585	20.6%	2.4	29.1%	0.56
6	2100	640	3225	25.7%	2.3	30.5%	0.67
7	2150	610	3835	30.5%	2.5	28.4%	0.79
8	1800	530	4365	34.8%	2.4	29.4%	0.89
9	2200	530	4895	39.0%	3.2	24.1%	1.03
10	1880	375	5270	42.0%	4.0	19.9%	1.16
11	1925	365	5635	44.9%	4.3	19.0%	1.29
12	1740	300	5935	47.3%	4.8	17.2%	1.43
13	2100	300	6235	49.6%	6.0	14.3%	1.58
14	1830	275	6510	51.8%	5.7	15.0%	1.71
15	1900	265	6775	53.9%	6.2	13.9%	1.86
16	1640	200	6975	55.5%	7.2	12.2%	1.99
17	1870	235	7210	57.4%	7.0	12.6%	2.14
18	1615	170	7380	58.8%	8.5	10.5%	2.27

Figure 5.108 Comparison of Instantaneous Oil Recoveries from Steamfloods in Homogeneous Horizontal Well Models for Runs 74, 75, 76 and 77.

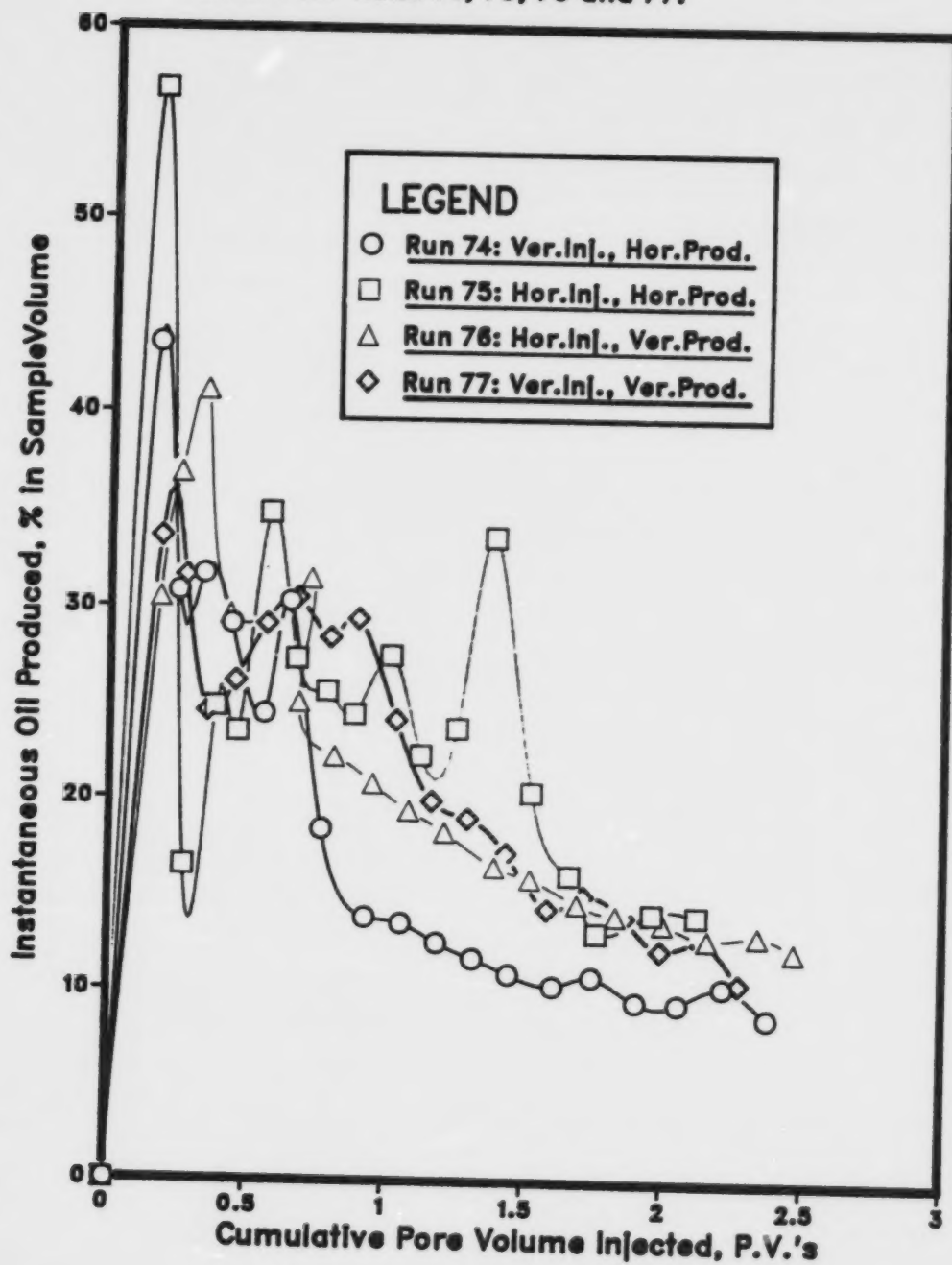
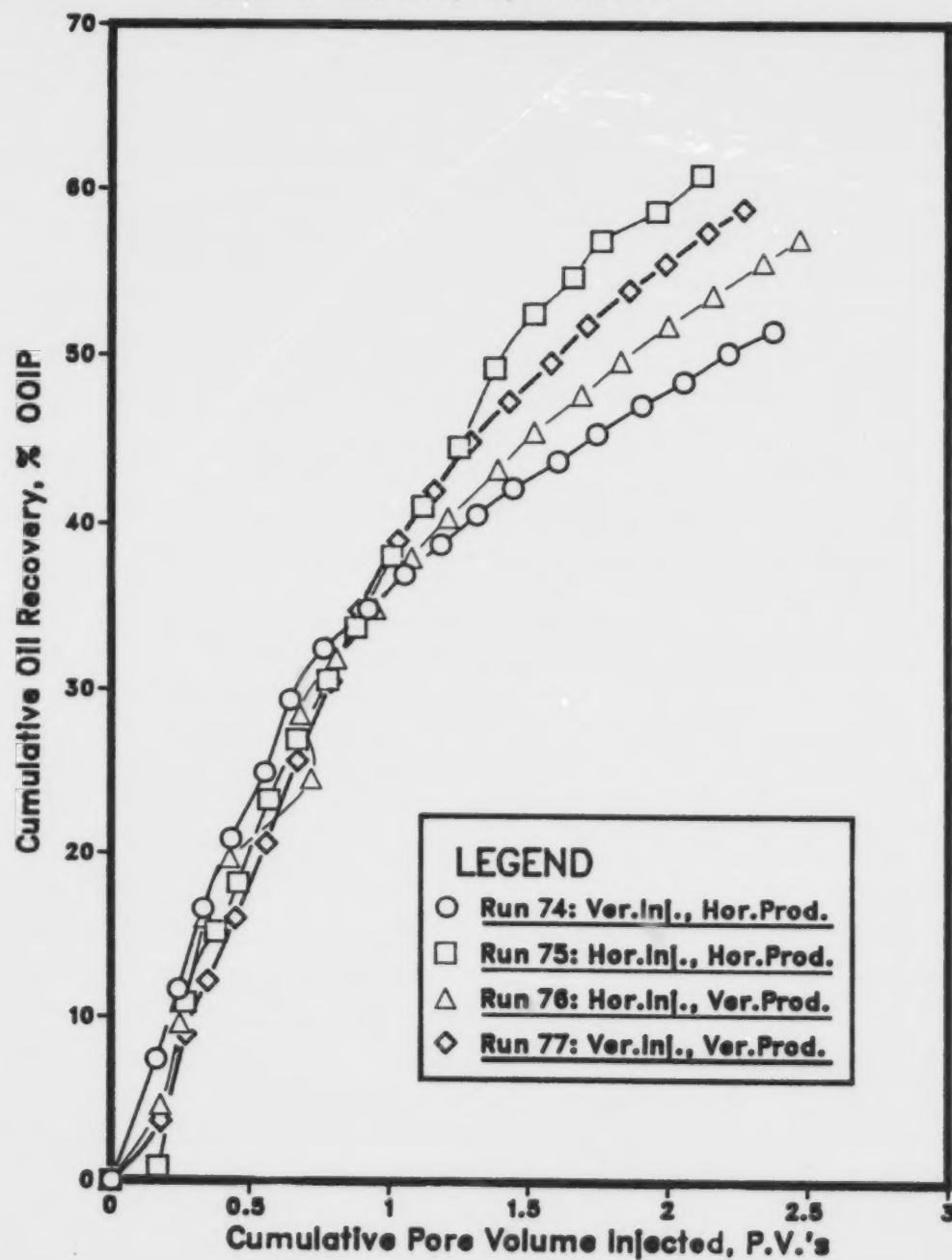


Figure 5.10 Comparison of Cumulative Oil Recoveries from Steamfloods in Homogeneous Horizontal Well Models for Runs 74, 75, 76 and 77.



Experimental Limitations and Sources of Error

As mentioned previously in the section dealing with scaling (Chapter 3), the assumptions made by Stegemeier, Laumbach and Volek⁹ lead to a certain degree of error in scaling the experiments. To adhere to strict scaling the capillary pressure and the relative permeability relationships would be required to be same functions of saturation in both model and the prototype. As well, there are practical considerations regarding the selection of model materials and fluids with properties that would exactly satisfy the scaling groups.

The inability to scale capillary pressure is believed to cause only a small error since a highly viscous crude oil occurs in the prototype reservoir. Demetre, Bentsen and Flock⁵⁸ reported that breakthrough recovery is only a weak function of the capillary number for large values of mobility ratio and provided a stable displacement exists. Bentsen⁵⁷ found that a displacement process in a linear system was dominated by mobility ratio. This made it possible to eliminate the requirement that relative permeabilities or their ratio be equal in the model and prototype for certain circumstances. It was suggested by Proctor²⁶ that two- and three-dimensional systems could also be dealt with in a similar manner.

Prats¹¹ reported that three-phase relative permeability curves used for a prototype at proper operating conditions could not be determined. Correspondingly it was not known how to establish the relative permeability properties for the laboratory model. Therefore it was difficult to determine if relative permeability relationships between the model and prototype were scaled or unscaled. Despite the limitation, Prats¹¹ found from his Peace River model study that good agreement was achieved between field and model performances.

Since different fluids and porous media are used in the model and prototype the relative permeability curves for the model and prototype will also be expected to be different. This is true even for the end points.

A feature of the Aberfeldy is that it is very stratified, however a limitation of the low pressure model was that representation of the stratification that exists in the reservoir could

not be achieved (i.e. the model permeability in the vertical and horizontal directions was the same). Despite this limitation, the effect of stratification decreases vertical permeability which would probably help to hinder the movement of solvent and steam downward into the bottom water zone and therefore improve oil recovery.

PART II
HORIZONTAL WELL FLOW MECHANICS

INTRODUCTION

This part of the report contains work dealing with the efforts undertaken to investigate horizontal wellbore flow mechanics. These work contain: the derivation of scaling criteria for flow from the reservoir into a horizontal producer and flow inside the horizontal well itself; the construction of a high-pressure scaled physical model based on the scaling criteria derived; and finally, the experiments carried out to test the various apparatus used in the research.

Altogether two types of physical models were used: low-pressure visual model and high-pressure model. The visual model was employed for 15 experiments which used nitrogen gas to displace water. The experimental results showed that a horizontal well could be an effective injector up to some critical injection rate, beyond which it could lead to earlier breakthrough of the injected fluid. The high-pressure model was employed for 6 experiments wherein actual oil and steam were used. For 2 of these runs actual heavy oil was used (Aberfeldy-type crude), and the remaining 4 experiments used a light, refined oil (FAXAM-100).

Chapter 6. LITERATURE REVIEW

Steam injection methods, like cyclic steam stimulation and steamflooding, play a prominent role in the recovery of heavy oils. They account for 90% of the heavy oils being produced. Their performances are especially good for thick and relatively homogeneous reservoirs. However, the performance declines appreciably for many so-called marginal reservoirs which are defined as thin (5 – 6m) and heterogeneous formations in communication with bottom water zones. In these cases, the heat losses to the surrounding formations, including the non-productive bottom water will be unacceptably high.

Furthermore, these marginal heavy oil reservoirs, found in Saskatchewan and Alberta, often occur at shallow depths (150 – 400 m below ground level). As such, the injected steam pressure required to mobilize and displace the highly viscous oils might exceed the overburden pressure and fracture the oil-bearing formation. This would create channels through which steam will channel without heating the formation efficiently. For these reasons, new strategies for steam injection have been proposed for these reservoirs. Most of them employ horizontal wells to improve the performance of steam processes.

6.1 Scaled model studies of steam processes

Physical models have been used extensively to study hydrodynamic phenomena. In general, the models can be classified into three groups: unscaled, partially scaled, and fully scaled. Unscaled models are easy and inexpensive to build and operate. They are used mainly to detect and observe new flow phenomena. Because of their unscaled nature, these models cannot be used to accurately predict flow conditions quantitatively. Partially scaled models are more expensive and difficult to build and operate. For these models some aspects of the flow process under investigation are scaled while the other aspects are not. To use these models some knowledge of the process is required. They can be used to provide some quantitative predictions for the flow process, especially with respect to those aspects that are scaled. Fully scaled models are most complex and difficult to build and operate. Every aspect of the flow process under study is scaled. Complete knowledge of the most important mechanisms of the process is required. In return, these models can be confidently and accurately utilized to analyze and predict various flow processes. In reality it is almost always impossible to have fully scaled models. This is especially true for models used to study the flow of fluids in porous media. Partially scaled and fully scaled models require that scaling groups have to be derived and used in their construction and operation.

Leverett *et. al.*¹⁴ were the first to apply scaling laws to model study the flow of fluids in petroleum reservoirs. They used dimensional analysis to obtain the dimensionless groups governing the water drive

process. Subsequently, other authors including Rapoport and Leas⁹⁶, Croes and Schwarz⁹⁷ extended the above analysis, again using dimensional analysis, to examine various parameters involved in the displacement of light oils by cold water. Offeringa and Van der Poel⁹⁸ used the same approach to carry out model experiments on oil recovery by solvent injection. It should be mentioned that there are two different techniques to obtain the scaling groups for partially and fully scaled models: dimensional analysis and inspectional analysis.

Historically, dimensional analysis was extensively used for early scaled model studies of reservoir fluid flows. Only recently has the second technique, inspectional analysis, been utilized to determine the scaling groups for scaled model experiments. It has gained more and more favour among various investigators.

Dimensional analysis is based on the Buckingham π -theorem. It requires that all of the relevant variables to the flow process being studied are known prior to the actual analysis. These variables could then be arranged in a set of dimensionless groups. The set is complete if all the groups in the set are independent of each other, and if every dimensionless group containing the same variables, and not belonging to the set can be formed by combining groups belonging to the set. A more complete treatment of dimensional analysis and its application to scaled models can be found in Langhaar's work⁹⁹.

Inspectional analysis, on the other hand is more systematic in its approach of getting the dimensionless groups. With this technique, equations relating the independent and dependent variables as well as constants of a process serve as the initial basis from which the set of dimensionless groups is obtained. This is done first by making the equations dimensionally homogeneous. Once this is completed, the dependent variables and constant terms can be brought into a dimensionless form by dividing each equation by one or more of its constants. It must be noted that in almost all instances the equations describing a flow process are differential, and as such relevant boundary and initial conditions need to be specified for the process to be completely described. These conditions will be handled in the same manner to obtain the set of dimensionless groups for the boundary and initial conditions.

Geertsma, Croes, and Schwarz¹² pointed out that in general the set of dimensionless similarity groups from dimensional analysis is bigger than that from inspectional analysis. However, the physical meaning of the similarity groups themselves as derived by dimensional analysis is generally less apparent than that of the groups derived by inspectional analysis. To illustrate these points they derived the dimensionless similarity groups for three types of oil displacement: cold-water drive, hot-water drive, and solvent injection. In all three cases it was observed as expected that dimensional analysis gave more groups than inspectional analysis, and also that the similarity groups derived by inspectional analysis were more flexible and useful

with respect to the realization of a scaled model.

As a consequence of the above considerations, as well as the belief that at the present time there is a lack of knowledge with respect to the variables relevant for the fluid flow process in the vicinity of a horizontal wellbore, the technique chosen for this work was inspectional analysis. Additionally, there have been numerous published scaled model studies of thermal recovery processes to date using inspectional analysis. It is hoped that by using inspectional analysis, some comparison between this work and the other studies can be made.

Work dealing specifically with scaling of steam injection processes has been carried out by a number of researchers. Pujol and Boberg¹⁷ examined the scaling accuracy of laboratory steamflooding models, especially with regards to the scaling of the capillary pressure. They found that for highly viscous oils accurate scaling of capillary pressure was not required. This was because the ratio of capillary to viscous forces was so low that unscaled capillary pressures had negligible effects on oil recovery. In the case of medium-viscosity oils (*less than 1000cp*), unscaled capillary pressures resulted in optimistic oil recovery. The authors further observed that for their study oil recovery depended mainly on the heat input per unit volume of reservoir sand. Injection rate was found to be a much less important parameter affecting oil recovery.

Stegemeier, Laumback, and Volek⁹ carried out scaled model studies for the Mt. Poso and Midway Sunset prototypes. The dimensionless similarity groups were obtained using inspectional analysis. The novel feature of their study was that vacuum models were employed. The experiments were conducted at pressures well below atmospheric pressure. Innovative techniques were devised with respect to materials selected to represent the porous media and reservoir fluids to ensure dimensional similarity between the models and their prototypes. Their experiments showed that the quantity of steam injected is the most important factor affecting the amount of oil produced.

Other notable scaled model studies of thermal recovery of heavy oils include those by Huygen and Lowry, Jr.,²⁰ Singhal,¹⁰⁰ Ehrlich,¹⁹ and Prats.¹¹ All of these dealt with Alberta heavy oil deposits. Information of other scaled model studies is contained in Farouq Ali and Redford's work,⁸ which also examined the scaling groups derived by different authors. Kimber, Farouq Ali, and Puttagunta^{10,101,102} presented an innovative and comprehensive analysis to obtain new scaling criteria for steam and steam-additive recovery experiments. In these studies both dimensional analysis and inspectional analysis were used to obtain the set of similarity groups. The same conclusion as that by Geertsma *et. al.*¹² was reached: the set of similarity groups derived by dimensional analysis was bigger than that derived by inspectional

analysis. The authors pointed out that it was very difficult to satisfy every single of the scaling criteria physically. Hence some scaling groups had to be relaxed. Five different approaches were adopted, each approach scaling one of the perceived five most important mechanisms associated with the overall process while relaxing the remainings. High pressure models were then constructed and operated according to the five resulting sets of scaling criteria for the five approaches. Experimental data were then compared to determine the validity of the relaxation of some of the scaling groups.

6.2 Scaled model studies of horizontal wells

Horizontal wells have been around for a number of years, but only recently have they been put into use in the recovery of petroleum fluids. Merkulov and Borisov¹⁰³ examined the flow potentials of horizontal and highly-deviated wells. They proposed different formulae to determine the production rates of single and groups of multiple deviated wells arranged in various well configurations. The Russians were also the first to field test the technology of drilling horizontal wells into heavy oil deposits from underground access, and using these wells to mobilize the oils. According to some sources the performance of this Russian field pilot at Yarega has been rather disappointing.

In the last 10 years horizontal wells have become popular with the oil industries in Western Europe and North America. Horizontal wells were successfully drilled and completed to augment the production of light and medium crudes from conventional vertical wells for various fields (Rospo Mare, offshore Italy; Prudhoe Bay, Alaska etc...). In all cases the results were spectacular: horizontal wells boosted daily field production rates several folds.⁹⁰ It was determined that the productivity index for a horizontal well, because of its larger contact area with the reservoir, could be 3-4 times that of a conventional, fully penetrating vertical well. It was also demonstrated that a horizontal well, when strategically placed, could reduce water or gas coning and thus improve the overall performance of a reservoir.⁷⁸ Horizontal well is believed to have a much better chance of intersecting systems of multiple vertical fractures, thus providing higher production rates, than a vertical well.¹⁰⁴

In Canada and other countries with large deposits of heavy oils and oil sands, horizontal wells are used to improve the performance of primary production as well as of various thermal recovery methods. Among the earliest published studies of the application of horizontal wells to thermal recovery of heavy oils is the work of Butler, McNab, and Lo.⁷⁶ This study examined the concept of steam-assisted gravity drainage of heavy oils into a horizontal well. It included theoretical analysis of the concept and scaled model experiments with visual and pressurized physical models. Steam-assisted gravity drainage involves the continuous injection of steam

into a steam chamber which expands slowly in different directions and mobilizes the surrounding bitumen by conduction first and later convection. The heated and mobilized bitumen is then drained continuously by gravity towards a horizontal well placed near the base of the formation. The authors pointed out that the main advantages of steam-assisted gravity drainage over conventional steam processes include a slower and more uniform displacement front leading to higher sweep efficiency, and the un-hindered flow of oil as it and steam flow separately and in opposite directions. Equations were derived to predict the rate of oil drainage and the lateral position of the steam chamber interface as functions of time and height of the steam chamber.

Experiments for the visual physical model were carried out at atmospheric pressure. Actual Cold Lake crude was used. The glass beads used to simulate the reservoir were carefully selected so that the permeability of the pack ensured the dimensional similarity between the model and the field. In the experiments, steam was injected near the top of the model and oil was drained from the bottom. Under such a setup the steam chamber would grow in the lateral directions only. The oil recovery was plotted against time, and the results were compared with those predicted by theory. The agreement between them was fairly good, even though it was found that the observed production rates were less than the predicted rates. This was attributed to smaller gravity heads in the model which were caused by the depletion of oil from the upper part of the model. A small modification was introduced into the equations to improve the accuracy of the analytical solution.

Other experiments were also conducted with scaled pressurized physical models. The steam pressure for these cases was 3 MPa. As with the visual model experiments, actual Cold Lake oil was used. Steam was again introduced into the top of the model, and oil produced from the bottom. It was noted that the flow in these experiments was radial rather than linear. The measured production rates were of the same order as predicted by theoretical relationships.

In summary, this was the first study of the steam-assisted gravity drainage concept. It lay the groundwork for the new method with extensive theoretical analysis of the concept, and validated it with experimental results.

Butler and Stephens⁷⁷ extended the previous study of steam-assisted gravity drainage to consider the effects of repeating well patterns on oil drainage rate. The pattern investigated in their study consisted of a series of parallel horizontal wells with a steam chamber above each. This geometry differed from that used in the previous work, as it represented a laterally bounded reservoir whereas the previous geometry was for a reservoir having no lateral boundaries. Again it was assumed that the steam chambers initially extended

throughout the vertical height of the reservoir above the horizontal wells, and that the direction of growth of the chambers was sideways. It was observed that the experimental drainage rate fell off as the reservoir became depleted, and that the newly modified theory gave results in reasonable agreement with those from the experiments.

It can be seen from the above studies that the physical model formulated and proposed was not complete, for it did not consider the movement of the steam chamber in the vertical direction. This deficiency could certainly explain the discrepancy between the experimental and theoretical results during initial production periods when the chamber grew predominantly in the vertical rather than sideways direction.

Butler, Stephens, and Weiss¹⁰⁵ attempted to rectify this deficiency in their study which considered both the vertical growth of the steam chamber from the base to the top of the reservoir, as well as the rate of growth in the lateral directions as the chamber rises slowly upwards. They assumed that the steam chamber was circular in shape, and that the centre of this circle was the horizontal well. Hence the rate of rise of the chamber was postulated to be the rate of increase of its radius. An equation was then derived to predict the height of the steam chamber with respect to time. It was pointed out by the authors that the result given by this equation would be optimistic since, in its derivation the restriction to the growth of the chamber by the top of the reservoir was not included. The predictive capability of this equation was tested against results of some visual model experiments, which showed a more rapid rise of the chamber than predicted. This experimental finding was attributed to the observed fact that the steam chamber, instead of being a single circle, was composed of many small steam fingers. This allowed faster penetration of steam into the heavy oil regions and consequently quicker rise of the steam chamber. Additional equations were given to allow the determination of the total drainage rate into a horizontal well from a rising steam chamber and the effective thickness of a mobile oil layer. It could be concluded that the new model presented in this study was rather simple in its formulation, yet surprisingly effective in its ability to predict the rate of vertical growth of steam chamber for the field.

Huygen and Black¹⁰⁶ conducted scaled model experiments to investigate the effectiveness of different horizontal and vertical well combinations in steamflooding Athabasca oil sand. They remarked that for accurate physical modelling of steaming through horizontal wells, both the heat flow (conduction and convection) and mass transport (due to gravity drainage and phase changes) must be scaled properly. Scaling criteria for the other parameters were obtained using the approaches derived by Pujol and Boberg,¹⁷ and Ehrlich.¹⁹ Injected steam pressure was set at 2.1 MPa. Most of the well configurations tested recovered more than half of the original oil in place, as well as achieved good oil-steam ratios. Performance

of the floods depended significantly on geometry.

Comparing the various geometries it was concluded that communication must be established between wells for the steamflood to be practical and efficient; horizontal fractures were an effective means to obtain injectivity for steamflooding; and horizontal steamflooding through a single horizontal well was a viable and productive strategy for mobilizing oil sand. The authors pointed out two deficiencies in their experiments: results were optimistic in so far as the model initial oil saturation was always higher than in the field, and they were rather conservative with regard to sideways growth of the steam chamber since the model horizontal permeability was lower (relative to the vertical permeability) than in the field. The study did not consider the effect of steam injection rate on the growth of the steam chamber and bitumen production rate.

Griffin and Trofimenkoff ⁷⁴ carried out model experiments to support Esso Resources' horizontal well pilot in the Cold Lake area. The experiments were of two different types: those conducted using a visual model and those using high-pressure models. The scaling criteria used to construct the models were those reported in the work by Butler, McNab, and Lo.⁷⁶ In the visual experiments, atmospheric pressure steam was injected into a horizontal injector located slightly above a horizontal producer. It was noted from these tests that good agreement was achieved between the theories derived by Butler *et.al.* ^{76,77} and experimental data with respect to oil production rate and horizontal growth rate of the steam chamber. The experiments also revealed that there was very little steam override at the top of the reservoir. This differed considerably from theoretical prediction.

In the high pressure model tests, high pressure steam (1.4 – 2.7 MPa) was injected into a vertical injector located above a horizontal producer. As was the case with the visual model tests, Cold Lake crude was used. In these cases, the experimental production rates were substantially higher than the theoretical predictions. Most of the extra production was believed to have come from steam chamber end zones, and this was confirmed by isotherm contour mapping of the steam chamber. As expected, increases in steam injection pressure and temperature did lead to increased oil production rates and reduced oil-steam ratios. In conclusion, it was pointed out by the investigators that their results from scaled model experiments agreed well with the theories developed in earlier studies.

Coates ¹⁰⁷ and Toma, Redford, and Livesey ¹⁰⁸ reported studies conducted using a horizontal well physical simulator in support of Texaco Canada Resources' horizontal and deviated-well project in the Athabasca region. Coates described the design and construction of the physical model as well as the operating procedure. No mention was made of any particular scaling approach used to determine the dimensions of the

model and properties of the porous pack. Actual oil sand was used to pack the porous medium which was subjected to simulated overburden and confining pressure. Steam pressure was set at 4450 KPa. Allowance was made for solvent injection along with steam. Experimental data including steam injection temperature, pressure, flow rate, oil production rate, and characteristic temperatures of the porous pack during a test were recorded, and analyzed to calculate the performance of the process. One notable feature of this physical model was that it was designed for the cyclic steam stimulation method. Hence it had only one single horizontal well which was used for both injecting the steam and producing the bitumen.

Toma, Redford, and Livesey examined the results of 14 experiments carried out using the above model. A linear regression model was employed to correlate oil recovery with other parameters such as the heat injected, axial pressure loss in the horizontal well etc... . Of great interest and importance was the finding that oil production during the drawdown stages was due mainly to the flashing of the oil and condensate in the steam chamber, as well as the penetration of steam along the horizontal well axis. Gravity drainage mechanism, in this case, played only a minor role in the recovery of oil. It was concluded that increasing the axial pressure drop could increase the production of horizontal well in cyclic operations. The regression model showed well pressure drop, heat ratio, open area of horizontal well to be parameters having the most influence on oil recovery. Injection of solvents like naptha also led to improved recovery performance.

Joshi ⁸⁹ provided a review of horizontal well steam technology. This included both scaled model and numerical studies. Mention was made of several laboratory studies employing vertical fractures above a horizontal well to help the vertical rise of the steam chamber and improve initial oil-steam ratios. All of the numerical studies listed in the review agreed on the superior performance of horizontal wells over conventional vertical wells.

Joshi ¹⁰⁹ extended previous work on steam-assisted gravity drainage to include the effects of well completion, shale barrier, and limited steam entry on oil recovery. Two basic well configurations were employed: horizontal injector and producer for one configuration, vertical injector and horizontal producer for the other. Two different geometries of the shale barrier were also used: continuous and discontinuous. Fairly good agreement between the theoretically predicted and experimental results was achieved.

It was concluded that the combination of vertical injector and horizontal producer yielded higher and more rapid oil recovery than the horizontal injector and producer combination for reservoirs with shale barriers. They had comparable performance for homogeneous and isotropic reservoirs. The presence of shale barriers was deemed to have no significant influence on final oil recovery. It did result in lower oil-steam ratios, and lower instantaneous oil production rates. It was recommended that for a reservoir with shale

barriers, a preferable location for a horizontal well was below a shale barrier discontinuity. Experimental data also indicated that limited steam entry caused by vertical fractures perpendicular to the horizontal well did not adversely affect the steam-assisted gravity drainage process. They rather provided an easier path for the vertical migration of steam, thus resulting in high initial oil production.

Chapter 7. DEVELOPMENT OF SCALING CRITERIA FOR MODEL

To derive the scaling groups by inspectional analysis the governing partial differential equations, along with appropriate constraints, constitutive relationships, boundary and initial conditions were formulated. These then were rewritten in terms of the dimensionless variables and their reference quantities, and the various similarity groups identified. For the problem under investigation it was of great importance that two different sets of scaling criteria were to be derived for the two distinctly different flow mechanisms involved in the overall process: flow of reservoir fluids from the porous medium to the horizontal well, and flow of fluids inside the horizontal well itself.

7.1 Flow of reservoir fluids from porous medium to horizontal well

This flow process was treated as three-phase flow (oleic, aqueous, vapour). Allowance was made for the injection of a steam-additive along with steam. This steam-additive was assumed to exist only in oleic and vapour phases. Diffusion and dispersion of the steam-additive between phases were not considered in the analysis. Additional assumptions were needed, and these included: mass transfer takes place due solely to convection; water may condense out of, or vaporize into steam; the porous medium is homogeneous and isotropic; rock compressibility and thermal expansion are negligible; system is always in local thermodynamic equilibrium; kinetic, potential, and viscous energies are negligible compared to thermal energy; dispersive and diffusive heat losses are small compared to conductive heat flux. Also, Darcy's law was assumed valid for fluid flow, i.e. there were no appreciable inertial effects. Similarly, Fourier's law was assumed valid for heat flow due to conduction. Furthermore, it was assumed that the fluids under consideration behave according to Newton's model for viscous fluids, and that their properties are independent of location. Instead, they are functions of fluid pressures, temperatures, and concentrations. These assumptions altogether led to the following governing partial differential equations, which were basically the conservation of various quantities. Figure 7.1 provides a sketch of a control volume used in the derivation of these equations.

Mass balance for oil:

$$\begin{aligned} \frac{\partial}{\partial t} (\phi S_o \rho_o C_{oo}) = & \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_o C_{oo} \frac{kk_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial r} - \frac{\rho_o g \partial(r \sin \theta)}{\partial r} \right) \right] \\ & + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_o C_{oo} \frac{kk_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial \theta} - \frac{\rho_o g \partial(r \sin \theta)}{\partial \theta} \right) \right] \\ & + \frac{\partial}{\partial Z} \left[\rho_o C_{oo} \frac{kk_{ro}}{\mu_o} \cdot \frac{\partial P_o}{\partial Z} \right] + q_o^* \end{aligned} \quad (7-1)$$

Mass balance for water:

$$\begin{aligned}
 \frac{\partial}{\partial t} (\phi S_w \rho_w + \phi S_g \rho_g C_{gw}) = & \\
 & \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_w \frac{kk_{rw}}{\mu_w} \cdot \left(\frac{\partial P_w}{\partial r} - \frac{\rho_w g \partial(r \sin \theta)}{\partial r} \right) \right] \\
 & + \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_g C_{gw} \frac{kk_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial r} - \frac{\rho_g g \partial(r \sin \theta)}{\partial r} \right) \right] \\
 & + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_w \frac{kk_{rw}}{\mu_w} \cdot \left(\frac{\partial P_w}{\partial \theta} - \frac{\rho_w g \partial(r \sin \theta)}{\partial \theta} \right) \right] \\
 & + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_g C_{gw} \frac{kk_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial \theta} - \frac{\rho_g g \partial(r \sin \theta)}{\partial \theta} \right) \right] \\
 & + \frac{\partial}{\partial Z} \left[\rho_w \frac{kk_{rw}}{\mu_w} \cdot \frac{\partial P_w}{\partial Z} \right] + \frac{\partial}{\partial Z} \left[\rho_g C_{gw} \frac{kk_{rg}}{\mu_g} \cdot \frac{\partial P_g}{\partial Z} \right] \\
 & + q_w^* + q_g^* C_{gw}^*
 \end{aligned} \tag{7-2}$$

Mass balance for steam-additive:

$$\begin{aligned}
 \frac{\partial}{\partial t} (\phi S_o \rho_o C_{oa} + \phi S_g \rho_g C_{ga}) = & \\
 & \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_o C_{oa} \frac{kk_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial r} - \frac{\rho_o g \partial(r \sin \theta)}{\partial r} \right) \right] \\
 & + \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_g C_{ga} \frac{kk_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial r} - \frac{\rho_g g \partial(r \sin \theta)}{\partial r} \right) \right] \\
 & + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_o C_{oa} \frac{kk_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial \theta} - \frac{\rho_o g \partial(r \sin \theta)}{\partial \theta} \right) \right] \\
 & + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_g C_{ga} \frac{kk_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial \theta} - \frac{\rho_g g \partial(r \sin \theta)}{\partial \theta} \right) \right] \\
 & + \frac{\partial}{\partial Z} \left[\rho_o C_{oa} \frac{kk_{ro}}{\mu_o} \cdot \frac{\partial P_o}{\partial Z} \right] \\
 & + \frac{\partial}{\partial Z} \left[\rho_g C_{ga} \frac{kk_{rg}}{\mu_g} \cdot \frac{\partial P_g}{\partial Z} \right] \\
 & + q_o^* C_{oa}^* + q_g^* C_{ga}^*
 \end{aligned} \tag{7-3}$$

Energy balance

$$\frac{\partial}{\partial t} \left[(1 - \phi) \rho_r U_r + \phi S_o \rho_o U_o + \phi S_w \rho_w U_w + \phi S_g \rho_g U_g \right] =$$

$$\begin{aligned}
& \frac{1}{r} \frac{\partial}{\partial r} (r K_{hr} \cdot \frac{\partial T}{\partial r}) \\
& + \frac{1}{r^2} \frac{\partial}{\partial \theta} (K_{hr} \cdot \frac{\partial T}{\partial \theta}) \\
& + \frac{\partial}{\partial Z} (K_{hr} \cdot \frac{\partial T}{\partial Z}) \\
& + \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_o \frac{h_o k k_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial r} - \rho_o g \frac{\partial(r \sin \theta)}{\partial r} \right) \right] \\
& + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_o \frac{h_o k k_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial \theta} - \rho_o g \frac{\partial(r \sin \theta)}{\partial \theta} \right) \right] \\
& + \frac{\partial}{\partial Z} \left[\rho_o \frac{h_o k k_{ro}}{\mu_o} \cdot \frac{\partial P_o}{\partial Z} \right] \\
& + \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_w \frac{h_w k k_{rw}}{\mu_w} \cdot \left(\frac{\partial P_w}{\partial r} - \rho_w g \frac{\partial(r \sin \theta)}{\partial r} \right) \right] \\
& + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_w \frac{h_w k k_{rw}}{\mu_w} \cdot \left(\frac{\partial P_w}{\partial \theta} - \rho_w g \frac{\partial(r \sin \theta)}{\partial \theta} \right) \right] \\
& + \frac{\partial}{\partial Z} \left[\rho_w \frac{h_w k k_{rw}}{\mu_w} \cdot \frac{\partial P_w}{\partial Z} \right] \\
& + \frac{1}{r} \frac{\partial}{\partial r} \left[r \rho_g \frac{h_g k k_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial r} - \rho_g g \frac{\partial(r \sin \theta)}{\partial r} \right) \right] \\
& + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left[\rho_g \frac{h_g k k_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial \theta} - \rho_g g \frac{\partial(r \sin \theta)}{\partial \theta} \right) \right] \\
& + \frac{\partial}{\partial Z} \left[\rho_g \frac{h_g k k_{rg}}{\mu_g} \cdot \frac{\partial P_g}{\partial Z} \right] \\
& + q_a^* - q^*
\end{aligned} \tag{7-4}$$

Table 7.1 lists the constitutive relationships and constraints for the flow of reservoir fluids from the porous medium to the horizontal well. Appendix F shows the set of boundary and initial conditions chosen for this study. These, together with the above equations completely describe the stated flow phenomenon.

Figure 7.1 Sketch of control volume for reservoir flow

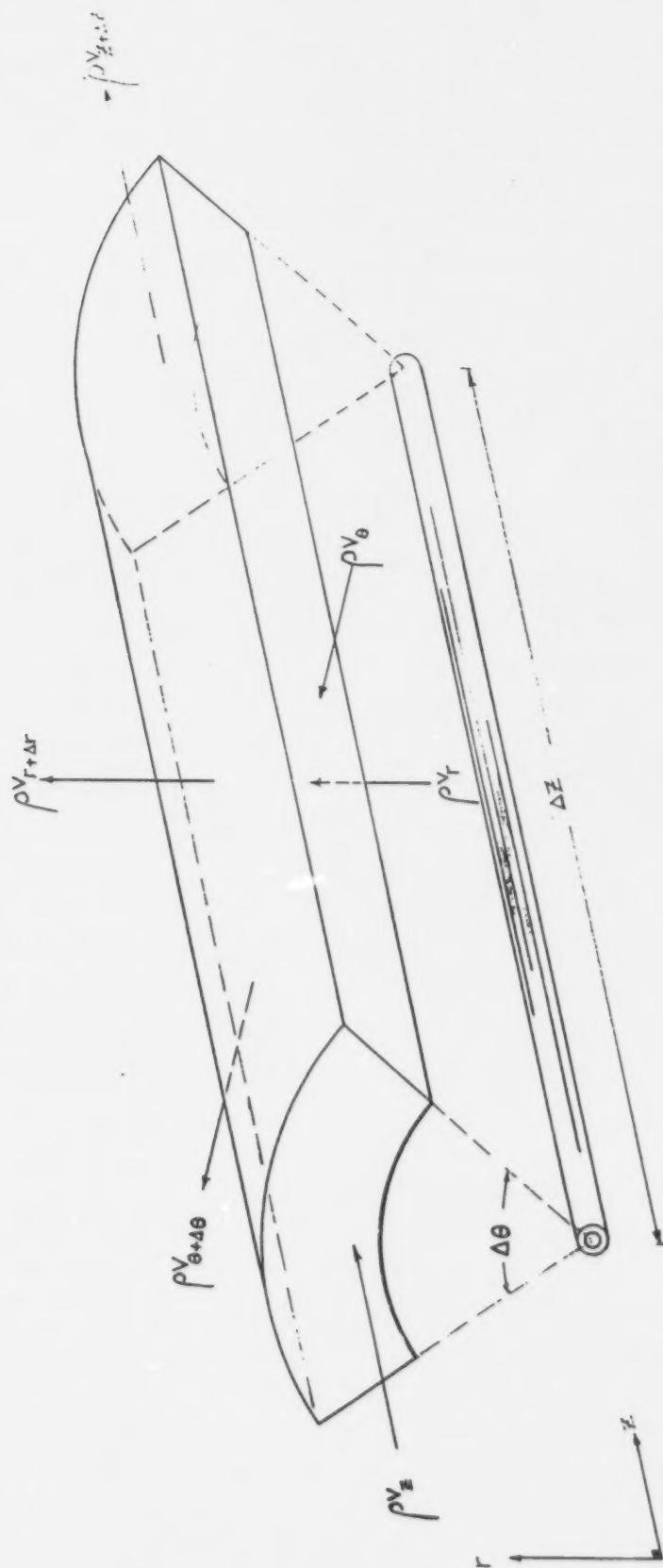


Table 7.1: Constraints and Constitutive relationships

a) Constitutive relationships

$$\rho_o = \rho_o(P_o, T, C_{oa})$$

$$\rho_w = \rho_w(P_w, T)$$

$$\rho_g = \rho_g(P_g, T, C_{ga})$$

$$\mu_o = \mu_o(P_o, T, C_{oa})$$

$$\mu_w = \mu_w(P_w, T)$$

$$\mu_g = \mu_g(P_g, T, C_{ga})$$

$$k_{ro} = k_{ro}(S_o, S_w, k)$$

$$k_{rw} = k_{rw}(S_o, S_w, k)$$

$$k_{rg} = k_{rg}(S_o, S_w, k)$$

$$h_o = h_o(P, T, C_{oa})$$

$$h_w = h_w(P, T)$$

$$h_g = h_g(P, T, C_{ga})$$

$$h_r = h_r(T)$$

$$K_{hr} = K_{hr}(T)$$

$$K_{hob} = K_{hob}(T)$$

$$\phi = \text{constant}$$

$$\rho_r = \text{constant}$$

$$g = \text{constant}(9.81 \text{ m/s}^2)$$

$$U_o = U_o(P, T, C_{oa})$$

$$U_w = U_w(P, T)$$

$$U_g = U_g(P, T, C_{ga})$$

b) Constraints

$$S_o + S_w + S_g = 1$$

$$C_{oo} + C_{oa} = 1$$

$$C_{gw} + C_{ga} = 1$$

$$P_g = P_o + P_{cgo}(S_o, S_w)$$

$$P_w = P_o - P_{cow}(S_o, S_w)$$

$$C_{gu} = K_{u,gu}(P, T, C_{gu})$$

$$\frac{C_{ga}}{C_{oa}} = K_{a,ga}(P, T, C_{ga}, C_{oa})$$

Each variable can be written in dimensionless form by dividing it by some characteristic reference quantity. For example, for the variable M , $M_D = M/M_R$, where M_D is the dimensionless form of the variable and M_R is some constant characteristic reference value. By substituting the above relationship into the governing partial differential equations, as well as the constraints, constitutive relationships, initial, and boundary conditions, these then take the form as shown in Table 7.2 for the mass balance of oil. Appendix G contains the other differential equations along with the associated physical descriptions in the same form.

Table 7.2: Mass balance of oil-written in terms of $M_D = M/M_R$

$$\begin{aligned}
& \left[\frac{\phi_R S_{oR} \rho_{oR} C_{oR}}{t_R} \right] \frac{\partial}{\partial t_D} (\phi_D S_{oD} \rho_{oD} C_{oD}) = \\
& \left[\frac{\rho_{oR} C_{oR} k k_{r,oR} P_{oR}}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD} C_{oD} k k_{r,oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{oR}^2 C_{oR} k k_{r,oR} g_R r_R \sin \theta_R}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD}^2 C_{oD} k k_{r,oD} g_D}{\mu_{oD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{oR} C_{oR} k k_{r,oR} P_{oR}}{r_R^2 \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD} C_{oD} k k_{r,oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{oR}^2 C_{oR} k k_{r,oR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD}^2 C_{oD} k k_{r,oD} g_D}{\mu_{oD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{oR} C_{oR} k k_{r,oR} P_{oR}}{z_R^2 \mu_{oR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{oD}^2 C_{oD} k k_{r,oD} g_D}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial z_D} \right) \\
& + q_{oR}^* q_{oD}^*
\end{aligned} \tag{7-5}$$

The reference quantities in the square brackets represent the coefficients for the terms in the equation. All coefficients have the same dimension. Similarity groups are determined by dividing the entire equation by one of these coefficients. This yields the dimensionless form of the equations and their similarity groups or dimensionless coefficients. For the mass balance of oil it was chosen to divide the entire equation by the first coefficient of the right hand side,

$$\left[\frac{\rho_{oR} C_{ooR} k k_{roR} P_{oR}}{r_R^2 \mu_{oR} r_D} \right]$$

i.e.,

Mass balance of oil in dimensionless form

$$\begin{aligned} & \left[\frac{\phi_R S_{oR} r_R^2 \mu_{oR}}{k k_{roR} P_{oR} t_R} \right] r_D \frac{\partial}{\partial t_D} (\phi_D S_{oD} \rho_{oD} C_{ooD}) = \\ & \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD} C_{ooD} k k_{roD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial r_D} \right) \\ & - \left[\frac{\rho_{oR} g_R r_R \sin \theta_R}{P_{oR}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD}^2 C_{ooD} k k_{roD} g_D}{\mu_{oD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\ & + \left[\frac{1}{\theta_R^2} \right] \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD} C_{ooD} k k_{roD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial \theta_D} \right) \\ & - \left[\frac{r_R^2 \rho_{oR} g_R \sin \theta_R}{\theta_R^2 P_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD}^2 C_{ooD} k k_{roD} g_D}{\mu_{oD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\ & + \left[\frac{r_R^2}{z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{oD}^2 C_{ooD} k k_{roD} g_D}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial z_D} \right) \\ & + \left[\frac{q_{oR}^* r_R^2 \mu_{oR}}{\rho_{oR} C_{ooR} k k_{roR} P_{oR}} \right] r_D q_{oD}^* \end{aligned} \quad (7-6)$$

The dimensionless form of the other governing equations as well as constraints, constitutive relationships, initial, and boundary conditions was obtained in a similar manner, and is listed in Appendix H. The set thus yielded may be replaced by any other set obtained from the products of the groups with any other group raised to any power. This allows some simplification and leads to the set of similarity groups which, after some simplifying assumptions can be reduced to the final set of scaling criteria. Table 7.3 illustrates the set of scaling criteria for fluids flow from the reservoir to the horizontal well.

Table 7.3: Scaling criteria for flow from reservoir to horizontal well

$$\begin{aligned}
& \frac{H}{2L}, \frac{\rho_w \mu g H \sin \theta_R}{2P_{oR}}, \frac{q_{oR}^* H^2 \mu_{oR}}{4 \rho_{oR} k_{roR} P_{oR}}, \frac{\rho_{wR}}{\rho_{oR}}, \frac{P_{oR}}{P_{wR}}, \frac{\rho_{sR}}{\rho_{oR}}, \frac{P_{oR}}{P_{sR}}, \\
& \frac{P_{sR}}{\rho_{wR}}, \frac{k_{sR} \mu_{sR}}{k_{roR} \mu_{oR}}, \frac{k_{wR} \mu_{wR}}{k_{roR} \mu_{oR}}, \frac{k_{sR} \mu_{sR}}{k_{roR} \mu_{oR}}, \frac{q_{wR}^*}{q_{oR}^*}, \frac{C_{sR}^* q_{sR}^*}{q_{wR}^*}, \\
& \frac{S_{wR}}{S_{oR}}, \frac{S_{sR}}{S_{oR}}, \frac{C_{sR}^* q_{sR}^*}{C_{oR}^* q_{oR}^*}, \frac{K_{hR} T_{hR} \mu_{oR}}{\rho_{oR} k_{roR} h_{oR} P_{oR}}, \frac{h_{wR}}{h_{oR}}, \\
& \frac{h_{sR}}{h_{oR}}, \frac{q_{sR}^*}{q_{oR}^* h_{oR}}, \frac{q_{sR}^*}{q_{oR}^*}, \phi_R, \frac{\rho_{oR} U_{oR}}{\rho_{oR} h_{oR}}, \frac{U_{oR}}{h_{oR}}, \frac{U_{wR}}{h_{oR}}, \frac{U_{sR}}{h_{oR}}, \frac{P_{sR}}{P_{oR}}, \frac{P_{sR}}{P_{oR}}, \frac{S_{sR}}{S_{oR}}, \\
& \frac{S_{wR}}{S_{oR}}, \frac{P_{sR}}{P_{oR}}, \frac{T_{sR}}{T_{oR}}, \frac{k_{hR} P_{oR}}{\phi_R S_{oR} \rho_{oR} U_{oR}}, \frac{q_{oR}^* H^2}{4 K_{hR} T_{oR}}, \frac{A_R^* K_{hR} T_{oR}}{V_{hR} q_{oR}^*}, \\
& \frac{q_{oR}^*}{q_{sR}^*}, \frac{h_{wR}^* q_{wR}^*}{q_{hR}^*}, \frac{h_{sR}^* q_{sR}^*}{q_{hR}^*}, \frac{h_{sR}^* q_{sR}^*}{q_{hR}^*}, \frac{C_{sR}^* q_{sR}^*}{q_{wR}^*}, \\
& \frac{C_{sR}^* q_{sR}^*}{C_{sR}^* q_{sR}^*}, \frac{h_{sR}^* q_{sR}^*}{q_{hR}^*}, \frac{h_{sR}^* q_{sR}^*}{q_{hR}^*}, \frac{q_{sR}^*}{C_{sR}^* q_{sR}^*}, \frac{q_{sR}^*}{C_{sR}^* q_{sR}^*}, \\
& \frac{W_R J_R L}{v_R h_R}, \frac{(C_{wR} + C_{sR}) T_R^* J_R L}{v_R h_R}, \frac{v_{sR} v_R \rho_{wR}}{P_{sR}}
\end{aligned}$$

7.2 Flow of reservoir fluids within the horizontal well

In this case, the flow was assumed to be two-phase and steady. It was known that the fluids flowing inside the horizontal well were incompressible and immiscible which consisted of heated bitumen and hot condensate. Further, it was assumed that these fluids can be treated as a single fluid whose density and viscosity could be approximated from the weight fractions of its two components, which can be guessed from the produced water-oil ratio. Figure 7.2 provides a sketch of the elemental control volume used as the basis for the derivation of the pertinent governing equations for the flow of fluid inside the horizontal well.

Mass balance of fluid inside horizontal well

$$\frac{dv}{dz} + \frac{v_{out} r^*}{2r_{in}^2} \cdot \frac{dr^*}{dz} - \frac{2a^* k k_{rm} r^*}{\mu_m r_{in}^2} \cdot \left[\frac{dP_m}{dr} + \frac{\rho_m g d(r \sin \theta)}{dr} \right] = 0 \quad (7-7)$$

It must be pointed out that in the derivation of the above equation it was assumed that the amount of heated bitumen and hot condensate flowing into the horizontal well was a function of the potential gradient between the reservoir and the horizontal well. Furthermore, to simplify the derivation it was assumed that the single fluid mentioned above—when flowing from the reservoir to the horizontal well—had an average density of ρ_m , an effective permeability of $k k_m$, and under a driving force of $\frac{\partial P_m}{\partial r}$.

It must also be noted that the symbol a^* signifies that only a fraction of the periphery of the horizontal well is open to the flow of fluid from the reservoir to the well. This is because only the regions of the reservoir located above the horizontal well are heated and mobilized by rising steam fingers. Regions at the sides of, and under the horizontal well are not contacted by steam fingers until much later.

To describe the momentum balance of the flow of fluid inside the horizontal well, an equation was taken from Table 3.4 - 3 (pp.85) of the book *Transport Phenomena* by R.B. Bird, W.E. Stewart, and E.N. Lightfoot.¹¹⁰ It describes the momentum balance of the flow of a Newtonian fluid having a constant density and viscosity inside a horizontal conduit. For the problem under investigation, the flow inside the horizontal well is axial, and the geometry of the horizontal well is symmetrical. Thus, v_θ and v_r are equal to zero, and the original equation is simplified to the form listed below, i.e.

Momentum-force balance of fluid flow inside horizontal well

$$\rho_m v = -\frac{dP_z}{dz} + \mu_m \cdot \left[\frac{1}{r^*} \frac{d}{dr^*} \left(r^* \frac{dv}{dr^*} \right) + \frac{d^2 v}{dz^2} \right] \quad (7-8)$$

The mass balance equation was then combined with the momentum balance equation to produce an expression relating the velocity gradient of the fluid stream flowing from one end of the horizontal well to the other with other variables including well pressure gradients, potential gradients between the reservoir and the horizontal well, fluid viscosity etc.... This single equation is of the following form,

Mass & Momentum balance of fluid flow inside horizontal well

$$\begin{aligned} \frac{2a^* k k_{rm} r^*}{\mu_m r_{in}^{*2}} \cdot \frac{d}{dz} \left(\frac{dP_m}{dr} \right) + \frac{2a^* k k_{rm} r^*}{\mu_m r_{in}^{*2}} \cdot \frac{d}{dz} \left(\frac{\rho_m g d(r \sin \theta)}{dr} \right) \\ - \frac{v_{out} r^*}{2r_{in}^{*2}} \cdot \frac{dr^*}{dz} + \frac{1}{\rho_m v} \cdot \frac{dP_m}{dz} - \frac{\mu_m}{\rho_m v} \left(\frac{1}{r^*} \frac{d}{dr^*} \left(r^* \frac{dv}{dr^*} \right) \right) \\ - \frac{\mu_m}{\rho_m v} \cdot \frac{d^2 v}{dz^2} = 0 \end{aligned} \quad (7-9)$$

To describe the energy conservation of the flow inside the horizontal well it was assumed that the convective heat transfer process due to the movement of the heated bitumen and hot condensate from one end of the well to the other end, as well as from the reservoir into the horizontal well is predominant when compared to the conductive heat transfer taking place between the fluids and the well.

Energy balance of fluid flow inside horizontal well

$$\begin{aligned} (C_m + C_p) \cdot \frac{dT^*}{dt} = W + \frac{d}{dz} \frac{v h}{J} + \frac{v_{out} h_{out} r^*}{2J r_{in}^{*2}} \cdot \frac{dr^*}{dz} + \frac{v_{out}^2 r^*}{2J r_{in}^{*2}} \cdot \frac{dr^*}{dz} \\ - \frac{2a^* k k_{rm} h_m r^*}{\mu_m r_{in}^{*2}} \cdot \frac{d}{dz} \left[\frac{dP_m}{dr} + \frac{\rho_m g d(r \sin \theta)}{dr} \right] \end{aligned} \quad (7-10)$$

The initial and boundary conditions for the flow of fluid from one end of the horizontal well to the other include

$$v(r^* = r_w, t) = 0$$

for no-slip condition at the wall of the horizontal well

$$T^*(r^*, z, t = 0) = 0$$

As was the case before with the development of the scaling criteria for the flow of fluids from the reservoir to the horizontal well, the above equations and initial, boundary conditions were also reduced into dimensionless form to allow the determination of the dimensionless similarity groups, i.e.

Dimensionless mass&momentum balance of fluid flow inside horizontal well

$$\begin{aligned}
 & \left[\frac{a_R^* k k_{rm} r_R^* P_{mR}}{\mu_{mR} r_{inR}^2 z_R r_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^*}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{dP_{mD}}{dr_D} \right) \\
 & + \left[\frac{a_R^* k k_{rm} r_R^* \rho_{mR} g_R \sin \theta_R}{\mu_{mR} r_{inR}^2 z_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^*}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{\rho_{mD} g_D d(r_D \sin \theta_D)}{dr_D} \right) \\
 & - \left[\frac{v_{oiR} r_R^*}{z_R r_{inR}^2} \right] \left(\frac{v_{oiD} r_D^*}{2r_{inD}^2} \right) \frac{dr_D^*}{dz_D} \\
 & + \left[\frac{P_{pR}}{\rho_{mR} v_R z_R} \right] \left(\frac{1}{\rho_{mD} v_D} \right) \frac{dP_{pD}}{dz_D} \\
 & - \left[\frac{\mu_{mR}}{\rho_{mR} r_R^*} \right] \left(\frac{\mu_{mD}}{\rho_{mD} v_D r_D^*} \right) \frac{d}{dr_D^*} \left(r_D^* \frac{dv_D}{dr_D^*} \right) \\
 & - \left[\frac{\mu_{mR}}{\rho_{mR} z_R^2} \right] \left(\frac{\mu_{mD}}{\rho_{mD} v_D} \right) \frac{d^2 v_D}{dz_D^2} = 0
 \end{aligned} \quad (7-11)$$

Dividing the above equation by the reference coefficient of the first term, $\left[\frac{a_R^* k k_{rm} r_R^* P_{mR}}{\mu_{mR} r_{inR}^2 z_R r_R} \right]$ led to the following,

$$\begin{aligned}
 & \left(\frac{2a_D^* k k_{mD} r_D^*}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{dP_{mD}}{dr_D} \right) \\
 & + \left[\frac{\rho_{mR} g_R r_R \sin \theta_R}{P_{mR}} \right] \left(\frac{2a_D^* k k_{mD} r_D^*}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{\rho_{mD} g_D d(r_D \sin \theta_D)}{dr_D} \right) \\
 & - \left[\frac{v_{oiR} r_R^* \mu_{mR} r_R}{a_R^* k k_{rm} P_{mR}} \right] \left(\frac{v_{oiD} r_D^*}{2r_{inD}^2} \right) \frac{dr_D^*}{dz_D} \\
 & + \left[\frac{P_{pR} \mu_{mR} r_{inR}^2 r_R}{\rho_{mR} v_R a_R^* k k_{rm} r_R^* P_{mR}} \right] \left(\frac{1}{\rho_{mD} v_D} \right) \frac{dP_{pD}}{dz_D} \\
 & - \left[\frac{\mu_{mR}^2 r_{inR}^2 z_R r_R}{\rho_{mR} r_R^3 a_R^* k k_{rm} P_{mR}} \right] \left(\frac{\mu_{mD}}{\rho_{mD} v_D r_D^*} \right) \frac{d}{dr_D^*} \left(r_D^* \frac{dv_D}{dr_D^*} \right) \\
 & - \left[\frac{\mu_{mR}^2 r_{inR}^2 r_R}{\rho_{mR} r_R^3 a_R^* k k_{rm} P_{mR} z_R} \right] \left(\frac{\mu_{mD}}{\rho_{mD} v_D} \right) \frac{d^2 v_D}{dz_D^2} = 0
 \end{aligned} \quad (7-12)$$

Dimensionless energy balance of fluid flow inside horizontal well

$$\begin{aligned}
 & \left[\frac{(C_{mR} + C_{pR}) T_R^*}{t_R} \right] (C_{mD} + C_{pD}) \frac{dT_D^*}{dt_D} = \\
 & \left(\frac{v_D h_D}{J_D} \right) \frac{d}{dz_D} \left(\frac{v_D h_D}{J_D} \right) \\
 & + \left[\frac{v_{oiR} h_{oiR} r_R^*}{J_R r_{inR}^2 z_R} \right] \left(\frac{v_{oiD} h_{oiD} r_D^*}{2J_D r_{inD}^2} \right) \frac{dr_D^*}{dz_D} \\
 & - \left[\frac{a_R^* k k_{rm} r_R^* P_{mR} h_{mR}}{\mu_{mR} r_{inR}^2 z_R r_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^* h_{mD}}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{dP_{mD}}{dr_D} \right)
 \end{aligned}$$

$$\begin{aligned}
& - \left[\frac{a_R^* k k_{mR} r_R^* h_{mR} \rho_{mR} g_R \sin \theta_R}{\mu_{mR} r_{inR}^2 z_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^* h_{mD}}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{\rho_{mD} g_D d(r_D \sin \theta_D)}{dr_D} \right) \\
& + W_R W_D
\end{aligned} \quad (7-13)$$

As was the case with the mass&momentum balance equation, the energy conservation equation of fluid flow inside the horizontal well was also reduced into the appropriate form whereby the dimensionless similarity groups are isolated by dividing the entire equation by the reference coefficient, $\left[\frac{v_R h_R}{J_R z_R} \right]$, i.e.

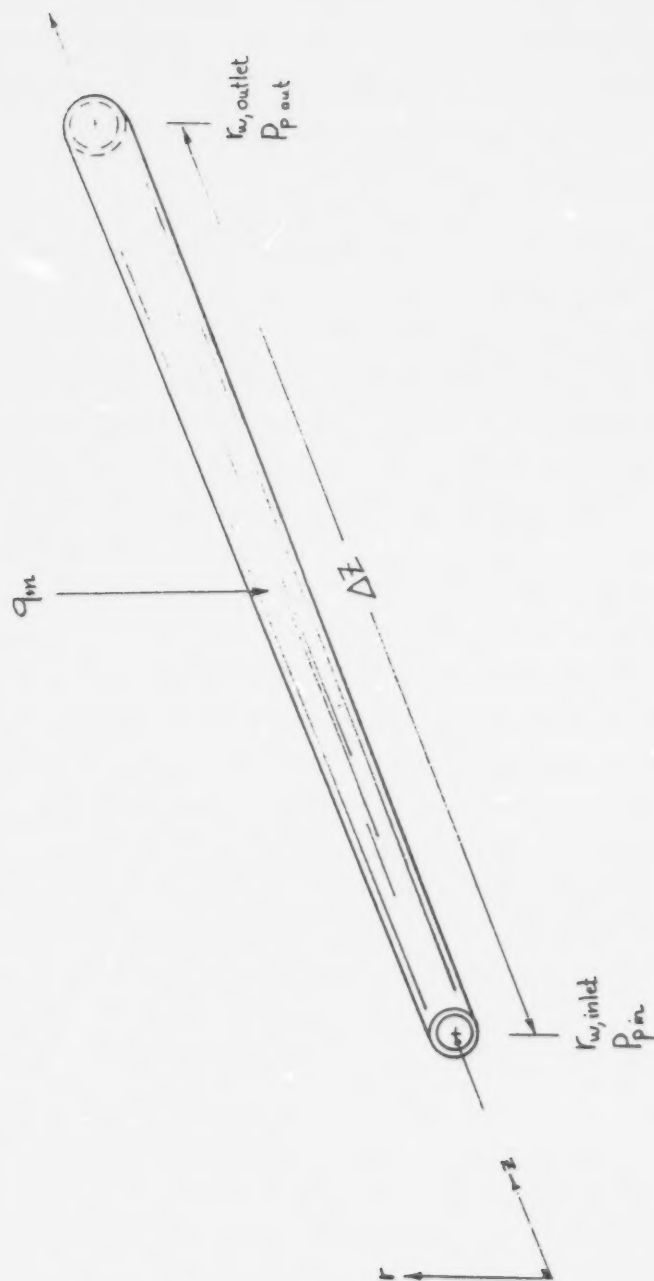
$$\begin{aligned}
& \left[\frac{(C_{mR} + C_{pR}) T_R^* J_R z_R}{v_R h_R z_R} \right] (C_{mD} + C_{pD}) \frac{dT_D^*}{dz_D} = \frac{d}{dz_D} \left(\frac{v_D h_D}{J_D} \right) \\
& + \left[\frac{v_{oR} h_R h_{oR} r_R^*^2}{v_R r_{inR}^2 h_R} \right] \left(\frac{v_{oD} h_D h_{oD} r_D^*^2}{2 J_D r_{inD}^2} \right) \frac{dr_D^*}{dz_D} \\
& - \left[\frac{a_R^* k k_{mR} r_R^* h_{mR} P_{mR} J_R}{\mu_{mR} r_{inR}^2 r_R v_R h_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^* h_{mD}}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{dP_{mD}}{dr_D} \right) \\
& - \left[\frac{a_R^* k k_{mR} r_R^* h_{mR} \rho_{mR} g_R \sin \theta_R J_R}{\mu_{mR} r_{inR}^2 v_R h_R} \right] \left(\frac{2a_D^* k k_{mD} r_D^* h_{mD}}{\mu_{mD} r_{inD}^2} \right) \frac{d}{dz_D} \left(\frac{\rho_{mD} g_D d(r_D \sin \theta_D)}{dr_D} \right) \\
& + \left[\frac{W_R J_R z_R}{v_R h_R} \right] W_D
\end{aligned} \quad (7-14)$$

Table 7.4 contains the set of scaling criteria for the flow of fluid going from one end of the horizontal well to the other.

Table 7.4: Scaling criteria for flow inside horizontal well

$$\begin{aligned}
& \frac{v_{w, outlet}}{v_{w, inlet}}, \frac{L}{r_{w, outlet}}, \frac{\rho_{mR} g_R h_R \sin \theta_R}{2 P_{mR}}, \frac{v_{oR} h_R h_{oR}}{v_R h_R}, \frac{4 v_R h_R r_R^*^2 v_{oR} h_{oR} P_{mR} J_R}{3 \mu_{mR} r_{inR}^2 h_R v_R h_R} \\
& \frac{W_R J_R L}{v_R h_R}, \frac{(C_{mR} + C_{pR}) T_R^* J_R L}{v_R h_R z_R}, \frac{v_{oR} h_R h_{oR}}{P_{mR}}
\end{aligned}$$

Figure 7.2: Sketch of control volume for horizontal well flow



Chapter 8. EXPERIMENTAL APPARATUS AND PROCEDURE

As was stated in the introductory paragraph, two types of experiments were carried out. The first type involved isothermal runs with the visual model, and the second consisted of actual steam injection experiments in the high-pressure physical model. The main purpose of the isothermal experiments was to examine two-phase flow characteristics (water and gas) in the vicinity of a horizontal wellbore. The high-pressure runs, on the other hand, were to determine the severity of the pressure loss experienced by fluid flow across the horizontal well, as well as to find the correlation between this pressure loss and oil recovery.

8.1 Experimental apparatus

8.1.1 High - pressure physical model

The apparatus used in this aspect of the study was designed and constructed based on the scaling criteria listed in the previous chapter. It must be noted that the primary objective at this stage was to test the various pieces of equipment. Hence, the operating procedure for the experiments carried out during this period did not necessarily satisfy some of the derived scaling criteria requirements.

The experimental setup can be divided into four sub-systems: the steam injection facility, the actual physical model, the production facility, and the data acquisition system. Figure 8.1 illustrates the overall apparatus setup for high-pressure runs. The steam injection facility consisted of a feed water pump, a steam generator, a back-pressure regulator, and water supply containers. A constant-injection-rate Milroyal pump was used to pump water from the containers into the steam generator. The pump was capable of injecting water over a wide range of rates, from *2.1 gallons per hour down to 0.21 gallons per hour* at pressures up to *2000 psi*. The steam generator was essentially a pressure vessel containing an oil bath. Heating rods were used to increase the temperature of the oil bath to up to *600°C*. Immersed in the oil bath were *40 feet* of coiling tubes. The feed water injected by the Milroyal pump travelling through the coiling tubes received energy from the oil bath heat source and became steam. A back-pressure regulator was used to set the injected steam pressure to the desired level. Steam pressure and temperature were measured, and adjusted if necessary, before steam was injected into the physical model.

The physical model representing the prototype reservoir was a steel-walled cylinder with flanges at both ends, as illustrated in Figure 8.2. The inside of the cylinder was *7.62 cm* (a scaling factor of 700 was used), and its length was *61 cm*. There were two rows, one on top and one in the bottom of the model, of openings. Altogether beside the two openings for production and saturation purposes in the end flanges, there were 10 openings: one was for steam injection, and the remaining 9 were for thermocouple probes.

The steam injection port was located in the top row, half way along the length of the model. The physical model was mounted on a rotatable stand—allowing it to be tilted at vertical, 45° *inclined*, and horizontal positions. The model was always placed in the vertical position during the packing and saturating processes, and horizontally during the determination of the permeability of the porous pack and the actual steam displacement experiments.

The production sub-system consisted of a back-pressure regulator and graduated cylinders. The pressure regulator was used to set the production pressure; and the graduated cylinders to collect the produced fluids at pre-determined time intervals. It was found that quite often it was necessary to centrifuge the production samples to obtain clear interface between the oleic and aqueous phases.

A detailed description of the data acquisition system can be found in Part I of this report. For the experiments carried out so far, the data acquisition system was set to scan and acquire data every 120 seconds. The experience so far was that the new data acquisition system performed flawlessly and free of breakdowns.

The horizontal well was constructed from sintered tubings of 5/8 in. This was mainly due to the unavailability of appropriate materials to satisfy the actual scaling criteria required for the well. On the other hand, the length of the horizontal well was properly scaled down using the same scaling factor as that used to determine the dimensions of the physical model. No screen was needed to prevent sand production into the horizontal well. The vertical steam injection well was constructed from regular metal tubings. The lowermost interval of the well (1 in) was perforated and covered with mesh. The well was selectively placed in the porous pack to achieve optimum steam injection effects with respect to preventing steam override.

The prototype porous medium was simulated by packing mesh # 3 glass beads. It was deemed that this mesh gives a porosity very much comparable with that of the prototype. De-aerated water was used to simulate reservoir connate water, and Aberfeldy crude was used to represent the bitumen of the prototype. Figure 8.3 showed the viscosity-temperature relationship for this heavy oil.

8.1.2 Visual model

Unlike the high-pressure physical model whose dimensions were determined by some of the derived scaling criteria, the visual model was not scaled. This was primarily because the visual model experiments were to be carried out at normal pressure and temperature conditions, and that their main purpose was to show fluid flow patterns in the vicinity of a horizontal wellbore. The visual model was a rectangular prism of length 120 cm, height 37 cm, and thickness 7 cm. It was constructed of Lucite flexi-glass, allowing

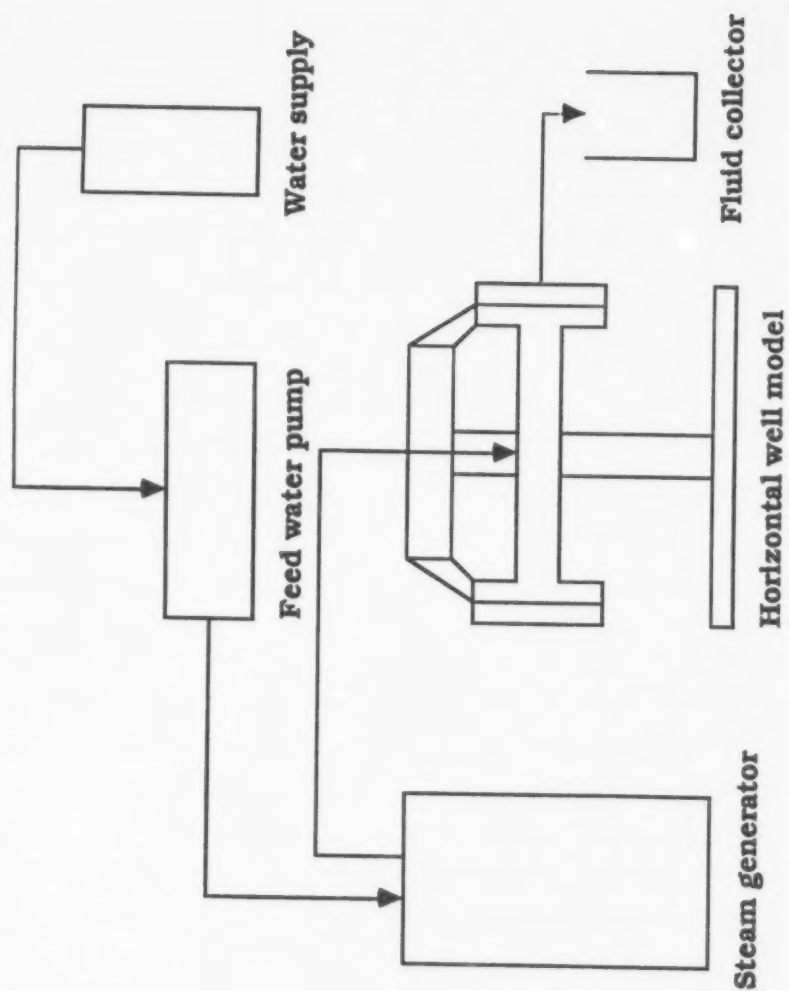


Figure 8.1: Apparatus setup for high-pressure model runs

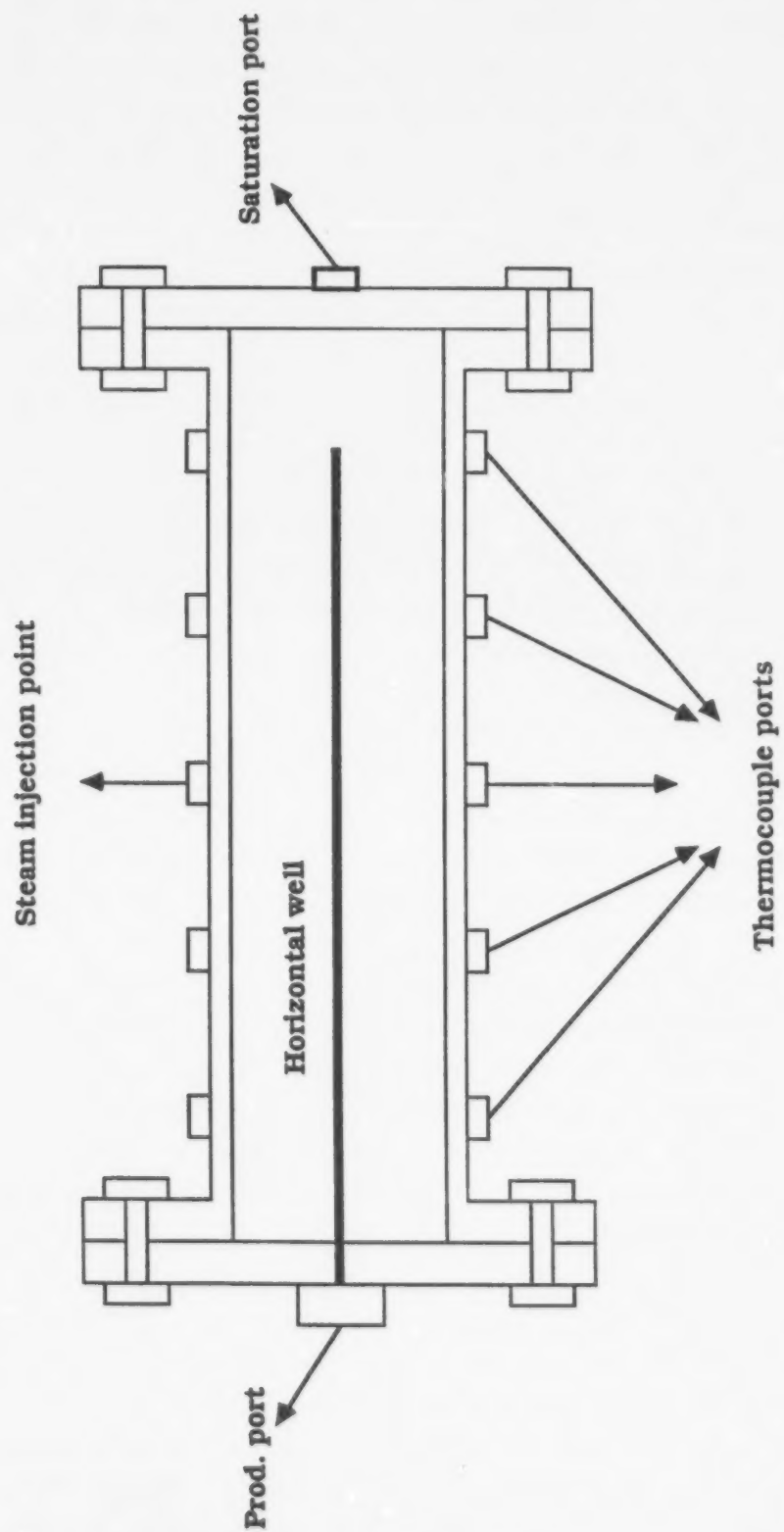


Figure 8.2: Horizontal well Physical model

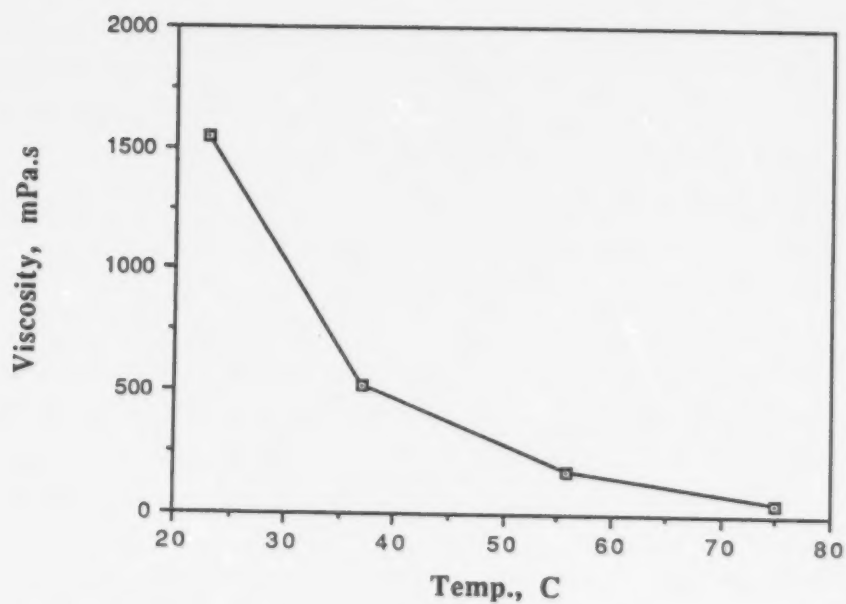


Figure 8.3: Viscosity-Temperature relationship of Aberfeldy oil

for visual observation and photographic recording of the displacement front as a function of time. Again, there was a number of openings around the sides of the model: 3 on top, 3 in the bottom, and 1 at each end cap. The inside of the prism was bounded on four sides (top, bottom, far, and near ends) with porous plates, which permitted the simulation of various outer boundary conditions. In these experiments, nitrogen gas at 2 – 3 *atmosphere* was injected into the model to displace dyed water. The 15 runs carried out with this model investigated the effects of gas injection rates, location of injection well, as well as the effectiveness of horizontal injection well on fluid production. Figure 8.4 shows the overall setup of the visual model experiments. The horizontal well in this case was constructed of perforated metal tubing. It extended the length of the model, and its interior was filled with glass beads. This was aimed to accentuate the pressure drop across the well length.

As was the case with the high-pressure experiments, the porous medium in the visual model runs was obtained by packing glass beads of mesh #3. No oil was used in these experiments. Instead, dyed water was used to represent reservoir fluids and nitrogen gas to simulate non-condensing steam.

8.2 Experimental procedure

8.2.1 *High – pressure physical model*

First, the cylindrical core holder was mounted in the vertical position. One end flange was bolted, as were the side openings. Water was poured into the core holder until it completely filled the inside volume. This, corrected for the dead volume of the small openings was the bulk volume of the physical model. The water was then allowed to drain out, and the core holder mounted horizontally. Thermocouple probes were secured in their openings. The production end cap was bolted to one end flange of the cylinder, and the core holder was rotated to its vertical position with the production end pointing downward, and the open end pointing upward. A mechanical shaker was then strapped on to the core holder and plugged in. A slurry mixture of glass beads and water was poured into the core holder. Tap water was also added along with the slurry mixture so that the water level was always about 5 *cm* above the slurry column. The water was allowed to drain slowly from the core holder through a partially open production valve at the end of the horizontal well. This was repeated until the core holder became completely filled with the slurry mixture. Excess slurry was wiped off, and the other end cap bolted on to the open end of the cylinder. Vacuum grease was next applied to ensure a perfect seal for the porous pack inside. It was believed that the mechanical vibrations of the core holder, in combination with the continuous withdrawal of water by gravity from the pack would lead to the desirable effect of settling the matrix materials (glass beads in this case) uniformly, and thus

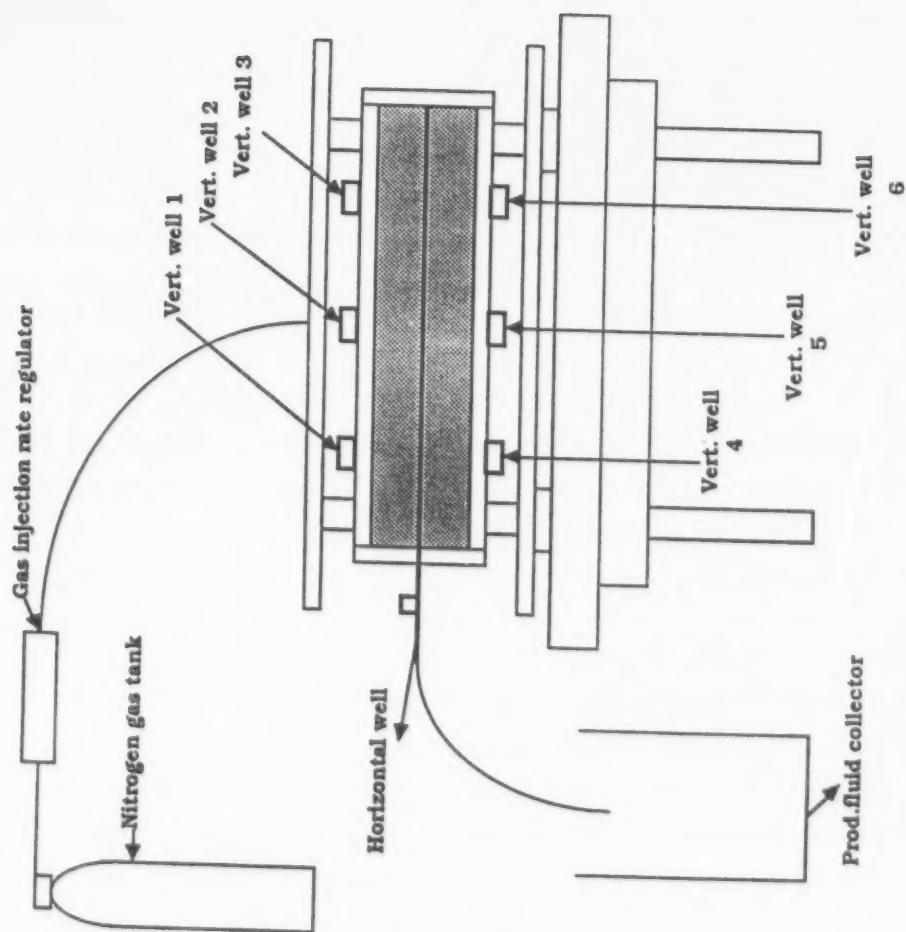


Figure 8 . 4 Apparatus setup for visual model runs

resulting in a homogeneous and isotropic porous medium.

High-pressure air was then passed through the core holder to remove all of the water from the pack. This process normally took about 8 – 12 hours for the glass beads to dry completely. Following this, the core holder was evacuated for several hours. At the end of this period there should be a good vacuum inside the core holder, and de-aerated water was then allowed to be drawn into the core holder by this vacuum. The volume of the water drawn in, adjusted to account for the dead space volumes due the thermocouple openings, was the pore volume. This was divided by the bulk volume to give the porosity of the porous pack.

The absolute permeability of the porous medium was determined next. It must be noted that at this stage the pack was fully saturated with water, and that the pressure inside the core holder was atmospheric. To determine the absolute permeability, the core holder was rotated to its horizontal position. A pressure differential of known magnitude was applied to the core holder. This was done by introducing a stream of pressured water into one end of the horizontal cylinder. A waiting period then followed to allow the pressure transient response to be uniformly distributed throughout the pack. After this time, the pressure inside the core holder was the same as the pressure applied on the injected water stream. The core holder was next opened to allow the water to drain. The water flow rate was taken, and recorded along with the fluid pressure. This procedure was repeated 7 – 8 times at different pressure settings—giving correspondingly different flow rates. A re-arranged version of Darcy's recti-linear flow equation was used to calculate the absolute permeability of the porous pack for each pressure differential setting, i.e.

$$k = \frac{q\mu L}{A\Delta P} \quad (8.1)$$

Given that

$$L = 0.61m$$

$$\mu = 1mPa.s$$

$$A = 0.00456m^2$$

Then the above equation became:

$$k = \frac{133.78q}{\Delta P} \quad (8.2)$$

with q in m^3 per sec, and ΔP in Pa

The average absolute permeability of the porous pack was then determined by arithmetically averaging all values of permeability within a reasonable range of each other. It was observed that there were always 2

or 3 permeability values very different from the range, and as such could inflate or deflate the average value significantly. These values should be left out of the averaging calculation. Furthermore, if large number of data points were collected, they would most likely converge to a single value of permeability which could then be taken as the representative absolute permeability of the porous medium.

At the end of the above process the porous pack was still fully saturated with water, but the pack pressure inside the core holder was no longer atmospheric. Instead, the pressure now was very close to the last pressure differential applied to the porous medium. The initial oil saturation and irreducible water saturation values for the porous medium must be known before any experiment could be carried out. To do this, the core holder was rotated to its vertical position but with the saturation port pointing downward, and the production port pointing upward. Oil was then pumped into the core holder from below, through the saturation port. This was to ensure a uniform displacement front and prevent the possible formation of viscous fingers. Care was taken to inject only oil, and no air into the pack. This oil injection was continued and stopped only when oil breakthrough at the production port was noticed. The difference between the volume of water drawn in initially and the volume of water displaced by oil, when divided by the pore volume gave the irreducible water saturation. The ratio between the total volume of oil injected into the core holder until oil breakthrough and the pore volume gave the initial oil saturation for the porous pack. The sum of these two saturation figures always added up to 1, as they should in the absence of any gas saturation.

Once all of the above work had been done, the experiment was now ready to be carried out. The thermocouple probes were connected to the EXP- 16 panels, the pressure transducers were re-calibrated, and the steam generator was switched on. Usually, it was necessary to wait approximatedly 1 hour for the temperature of the oil bath inside the generator to rise to the desired level. During this waiting period several tasks were completed: water supply containers were filled, feed water injection rate was set for the Milroyal pump, numbered graduated cylinders were assembled to collect soon-to-be- produced fluids, and the scanning rate for the data acquisition system was programmed into the computer system. The experiment began when steam at desired pressure and temperature started to be injected into the core holder. Produced fluids were collected into graduated cylinders and timed to give fluid production rates. The experiment continued until it was deemed that the cumulative steam-oil ratio had reached the economic limit of 15 : 1. Then the experiment was terminated. Throughout the course of an experiment the data sampling, except for the collection of produced fluids, was controlled and done automatically by computer.

After the experiment was terminated, the core holder was opened and the porous pack removed and discarded. The core holder was then cleaned, dried, and readied for the next experiment. It is hoped that

some improvements could be introduced in the next phase of research. Specifically, it is hoped that in the near future some specially designed augers could be manufactured to remove regions of the steamed porous medium prior to its discard. Some measures of the residual oil saturation could then be approximated to determine the sweep efficiency of the steam front. The data collected, including thermocouple and pressure transducer readings, were next analyzed to determine various parameters indicative of the overall performance of the steam injection experiment.

8.2.2 *Visual model*

There were some important differences in the experimental procedure for the visual model. This was expected because the visual model and the high-pressure model were designed for different purposes, and constructed from different materials. With respect to the packing process, it was more or less the same as with the high-pressure model—except for one important difference: there was no mechanical vibration of the visual model during the packing process. It was found that the visual model was rather fragile, and any shaking of the model could lead to its wreckage. The model also cannot withstand high pressure loadings, and as such it was necessary that much smaller pressure differential settings were used to obtain permeability data for the visual model experiments. This, coupled with the lack of mechanical vibrating during the packing process, led to a perhaps not surprising observation that the absolute permeability and porosity of the porous pack for the visual model experiments were always higher than for the high-pressure experiments.

Chapter 9. EXPERIMENTAL RESULTS AND DISCUSSION

Table 9.1 lists all of the experiments carried out during this research period. It includes the runs for both the visual model (Runs 1A-5C) and the high-pressure model (Runs HP 1-6).

9.1 *Visual model*

As stated previously, the purpose of the isothermal experiments carried out with the visual model was to obtain the characteristics of fluid flow in the vicinity of a wellbore—especially in the steam zone where steam condensation is minimal. In these runs, two primary objectives were investigated: the effectiveness of a horizontal well as an injector or producer, and the effect of injection rates on fluid recovery. Figure 9.1 showed plots of fluid recovery as a function of nitrogen gas injection rates for a typical run utilizing vertical injector and horizontal producer. Similarly, Figure 9.2 provided the profile of fluid recovery rate as function of nitrogen injection rates for the runs having horizontal injector and vertical producer. Figure 9.3-5 compared the performance of horizontal injector against that of vertical injector for any of the three injection rates used in the experiments. Data used to generate these plots are contained in Table 9.2.

It can be seen from these results that the fluid production profile was very similar in all cases, irrespective of whether the injector was horizontal or vertical. The production rate, in all instances, started off very high but then dropped off rapidly. Careful examination revealed that for the three horizontal injector runs—3A, 3B, and 3C—the drop in the fluid production rate was more pronounced, especially after about 50% of pore volume of nitrogen gas had been injected, than for the runs utilizing vertical injector and horizontal producer. Furthermore, for these three runs it was observed that higher gas injection rates resulted in lower fluid production rates as well as lower cumulative fluid recoveries. Gas breakthrough also occurred earlier as gas injection rate was increased. Most of these observations were in sharp contrast with the results for the other runs. When a vertical gas injector was used, it was always that the higher the gas injection rate the higher the fluid production rate. As well, cumulative fluid recovery increased when higher gas injection rates were used—even though the improvement was rather modest. Lastly, as in the three horizontal injector runs, increased gas injection rates resulted in earlier breakthrough of gas at the production well.

In general, it can be concluded that a horizontal injector could achieve better performance than a vertical injector for a suitably low gas injection rate. This can be explained by the fact that under existing experimental conditions the horizontal injector contacted more regions of the porous medium than the vertical well did. This advantage, however, could be negated as gas injection rate was increased—as illustrated in Figure 9.5. Each of the three horizontal injector runs resulted in significant improvement of cumulative

fluid recovery, as well as delayed the start of gas breakthrough at the producer.

Table 9.1: Summary of Experiments

Run no.	Type of exp.	Model	Fluids	Porous medium	Inj. well	Prod. well	Inj. rate
1A	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 1	Horizontal	1.75 ml/s
1B	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 1	Horizontal	2.56 ml/s
1C	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 1	Horizontal	5.68 ml/s
2A	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 2	Horizontal	1.75 ml/s
2B	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 2	Horizontal	2.56 ml/s
2C	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 2	Horizontal	5.68 ml/s
3A	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Horizontal	Vert., no. 5	1.75 ml/s
3B	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Horizontal	Vert., no. 5	2.56 ml/s
3C	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Horizontal	Vert., no. 5	5.68 ml/s
4A	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 4	Horizontal	1.75 ml/s
4B	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 4	Horizontal	2.56 ml/s
4C	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 4	Horizontal	5.68 ml/s
5A	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 5	Horizontal	1.75 ml/s
5B	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 5	Horizontal	2.56 ml/s
5C	Isothermal	Visual	Dyed water & Gas	Glass beads #3	Vert., no. 5	Horizontal	5.68 ml/s
HP 1	Thermal	High-pressure	Heavy oil & Water	Glass beads #3	Vertical	Horizontal	1 HCPV/hr
HP 2	Thermal	High-pressure	Heavy oil & Water	Glass beads #3	Vertical	Horizontal	1 HCPV/hr
HP 3	Thermal	High-pressure	Light oil & Water	Glass beads #3	Vertical	Horizontal	0.75 HCPV/hr
HP 4	Thermal	High-pressure	Light oil & Water	Glass beads #3	Vertical	Horizontal	1 HCPV/hr
HP 5	Thermal	High-pressure	Light oil & Water	Glass beads #3	Vertical	Horizontal	1 HCPV/hr
HP 6	Thermal	High-pressure	Light oil & Water	Glass beads #3	Vertical	Horizontal	0.75 HCPV/hr

Table 2: Production data for 2 types of visual runs

	Run 2A	Run 2B	Run 2C	Run 3A	Run 3B	Run 3C
Prod. rate@0.00 PV, ml/s	0	0	0	0	0	0
Prod. rate@0.05 PV, ml/s	1.67	2.63	4.55	8.33	7.69	5.51
Prod. rate@0.315 PV, ml/s	1.28	1.67	3.33	1.79	0.43	0.41
Prod. rate@0.631 PV, ml/s	0.37	0.66	1.82	0.41	0.094	0.27
Prod. rate@0.946 PV, ml/s	0.14	0.2	0.98	0.087	0.054	0.14
Prod. rate@1.262 PV, ml/s	0.07	0.16	0.2	0.05	0.032	0.085
Prod. rate@1.892 PV, ml/s	0.03	0.08	0.07	0.031	0.021	0.076
Gas bt(%PV inj.)	53	50	48	152	110	79
Recovery@bt(% PV)	35	41	43	55	49	45
Total recovery(% PV)	43	44	47	64	60	57

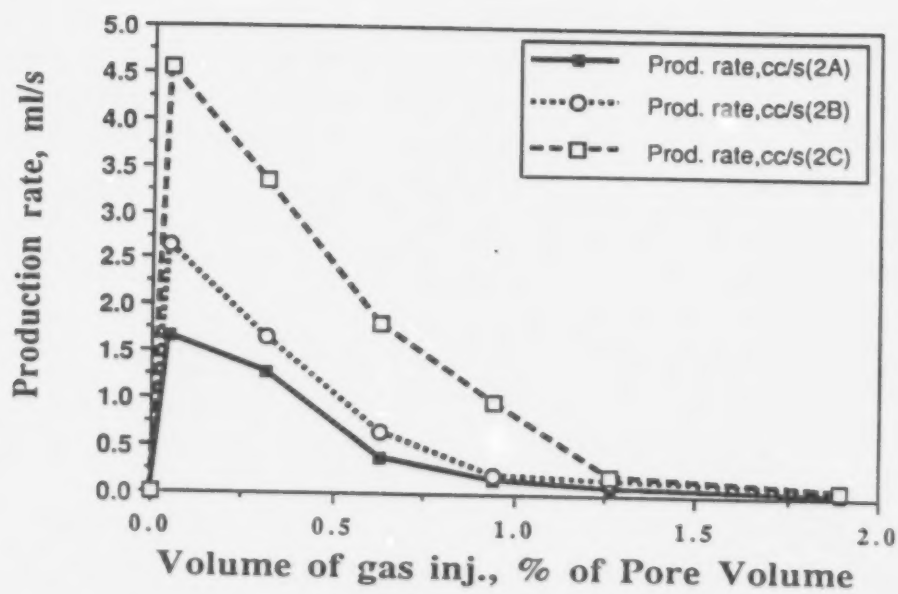


Figure 9.1: Fluid prod. rate vs. Vol. of gas inj.
(Vertical injector, Horizontal producer)

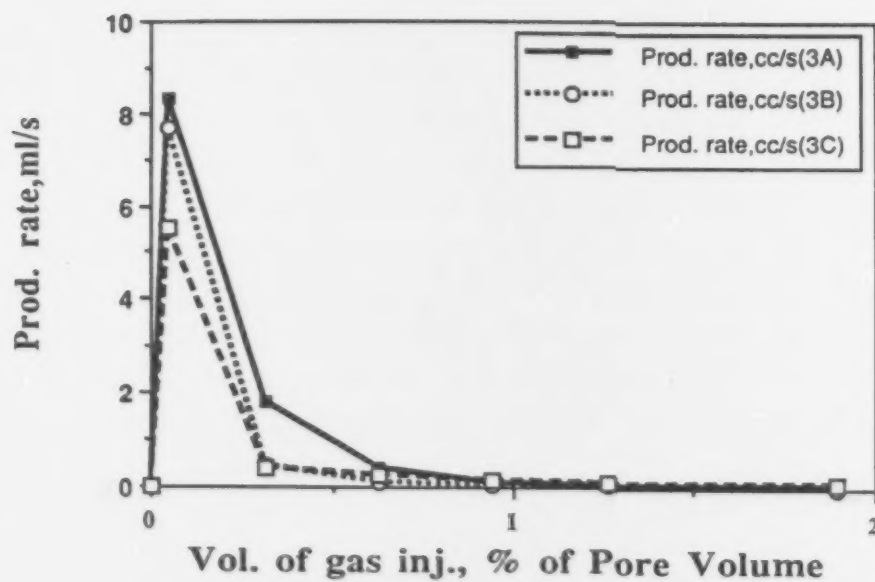


Figure 9.2 : Fluid prod. rate vs. Vol. of gas inj.
(Horizontal injector, Vertical producer)

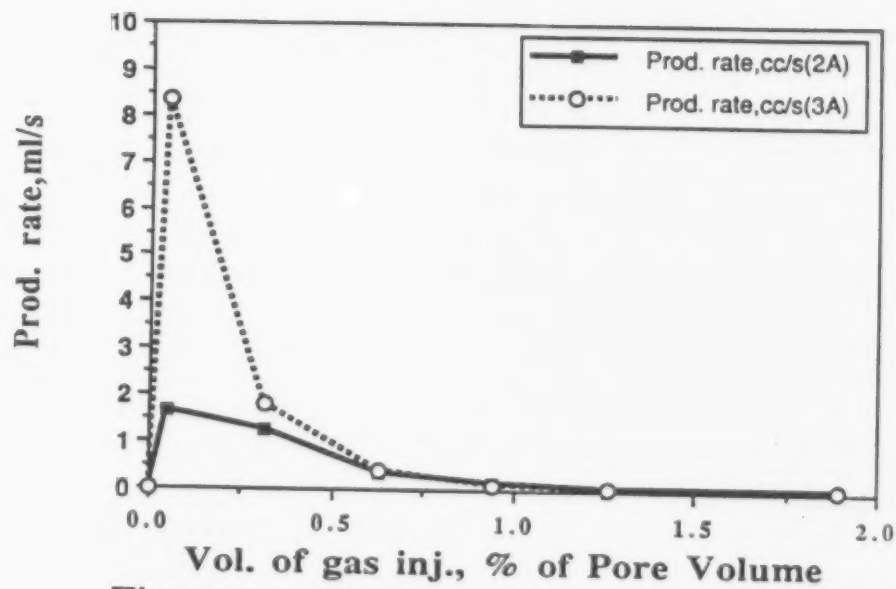


Figure 9.3: Fluid prod. rate vs. Vol. of gas inj.
(Gas inj. rate=1.76 ml/s)

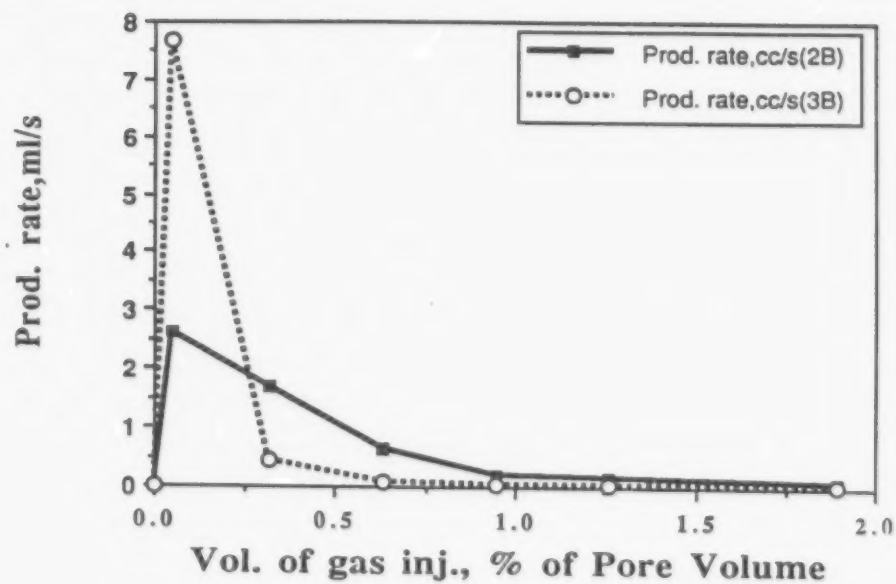


Figure 9.4 : Fluid prod. rate vs. Vol. of gas inj.
(gas inj. rate= 2.56 ml/s)

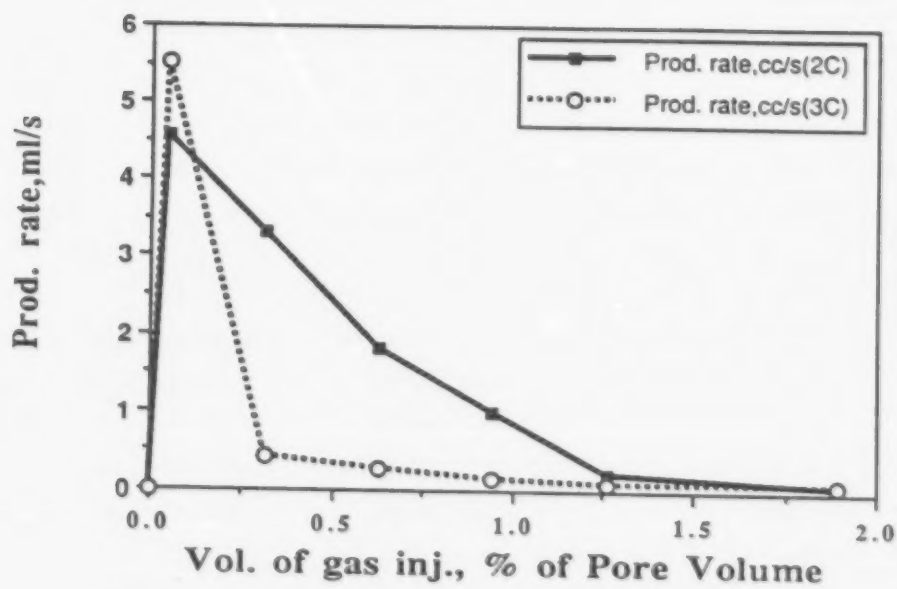


Figure 9.5: Fluid prod. rate vs. Vol. of gas inj.
(gas inj. rate= 5.68 ml/s)

9.2 High - pressure model

Of the six experiments carried out with the high-pressure model, two were steam injection runs to displace heavy oil (run HP 1 and HP 2) while the remaining runs (HP 3-6) used refined light oil (FAXAM-100). This was mainly because of the limited availability of heavy oil, as well as due to the fact that at this stage the research was mainly concerned with testing the various pieces of equipment and the overall experimental design. For the next phase of study it is envisaged that all of the high-pressure runs will use actual heavy oil. Figure (9.6-8) showed the plots of instantaneous fluid production rate, well pressure drop, and cumulative fluid production—all as functions of volume of steam injected—for a heavy oil run (run HP 2), while Figure (9.9-11) showed the same plots for a typical light oil run (run HP 4). Table 9.3-4 list the experimental data for these two high-pressure model experiments.

As in the cases of the isothermal experiments with the visual model, the fluid production rate curve for the steam injection experiments was typical of horizontal well: high initial production rates followed by rapid declines in later periods. There was some mild fluctuation in the production rate for the heavy oil runs, as shown in Figure (9.6), but it was felt that this was more likely due to experimental procedure than to anything else. It was observed that the well pressure differential curve, in all six cases, followed the same trend of the instantaneous fluid production curve: large pressure drop during initial periods and smaller pressure drop later on. The correlation between these two curves was especially compelling during the first part of the experiments, after about 40% of HCPV of steam had been injected. Higher steam injection rates seemed to result in earlier breakthrough of steam at the horizontal production well. Furthermore, it was seen from temperature profiles of the porous medium throughout the duration of the runs that the steam chamber did grow preferentially in the direction of the production outlet. This was expected as that was the path of least resistance for steam to travel.

The viscosity of the oils did play an important role in the recovery of oil. Runs HP 3-6 did result in better ultimate fluid recovery, with respect to the initial amount of oil in place. Additionally, the temperatures of the first few production samples for these runs took very little time to become hot—whereas they took considerably longer to warm up for the two heavy oil runs (HP 1-2). There was no practical means to measure the residual oil saturation in place followed each run, but it was concluded from examining the production samples that the amount of oil left behind in the light oil runs was less than in the two heavy oil runs. One of the improvements in experimental procedure planned for future runs is concerned with this matter. It is hoped that some specially designed and constructed augers would be available to remove

portion by portion regions of the porous medium followed each experiment to determine the residual oil saturation in various areas of the pack, and thus also the sweep efficiency of the injected steam.

Table 3: 3 Production data for run HP 2

Time elapsed (min)	Vol. of steam inj. (% of HCPV)	Press. diff. (KPa)	Inst. fluid prod. (ml)	Cumul. fluid prod. (ml)	Inst. fluid prod. rate (ml/s)
4	6.67	9.76	53	53	0.22
8	13.33	9.09	52	105	0.22
10	16.67	7.41	50.5	155.5	0.42
12	20	5.25	50	205.5	0.42
16	26.67	4.85	51	256.5	0.21
20	33.33	3.21	50	306.5	0.21
24	40	-1.21	51.5	358	0.21
36	60	4.04	99	457	0.14
48	80	-0.07	91	548	0.13
56	93.33	-2.83	100.5	648.5	0.21
68	113.33	0.88	118	766.5	0.16

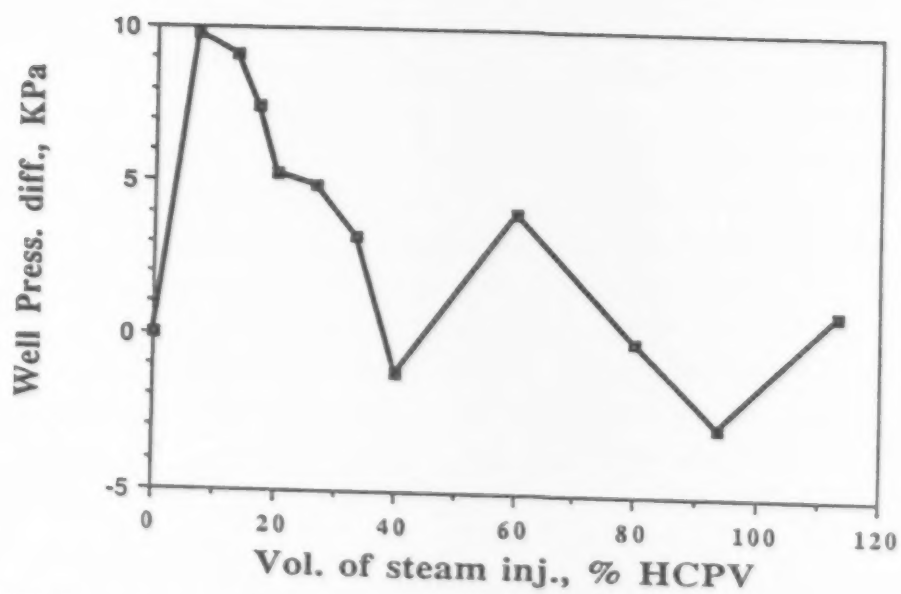


Figure 2.6 : Well press. diff. vs. Volume of steam injected
(Run HP 2)

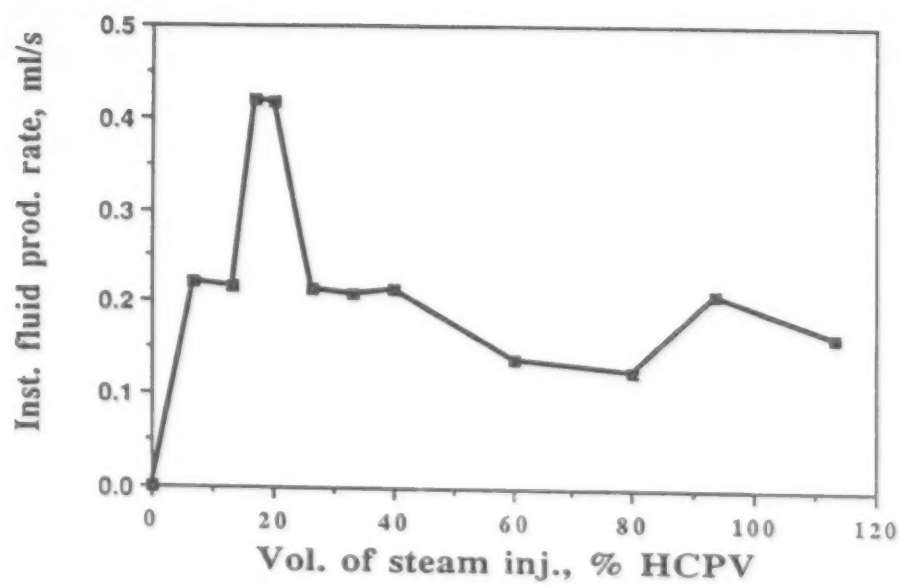


Figure 9.7: Inst. fluid prod. rate vs. Vol. of steam inj.
(Run HP 2)

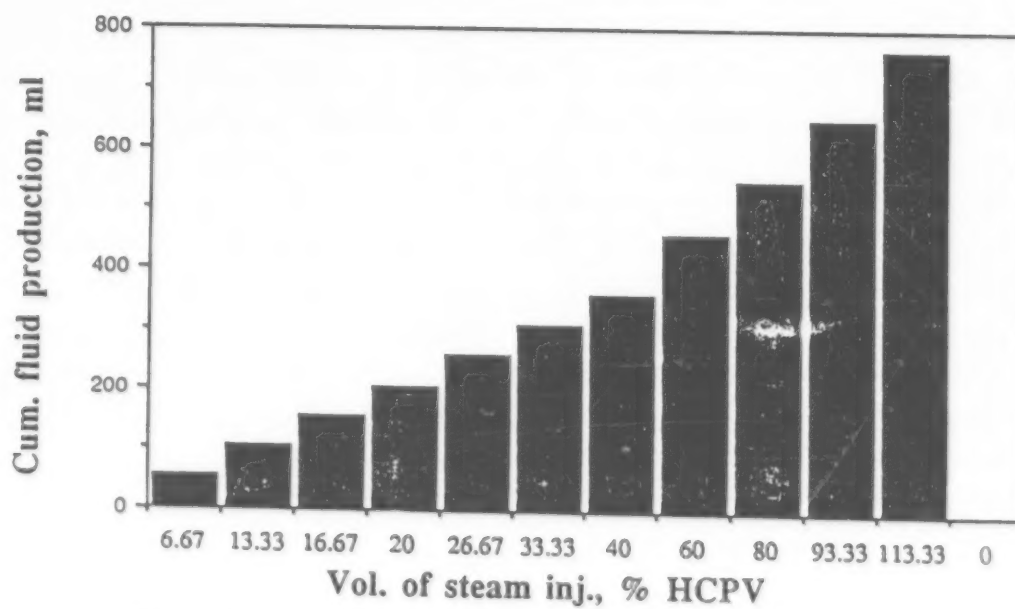


Figure 9.8 : Cum. fluid prod. vs. Vol. of steam inj.
(HP 2)

Table 9. 4 Production data for run HP 4

Time elapsed (min)	Vol. of steam inj. (% of HCPV)	Press. diff. (KPa)	Inst. fluid prod. (ml)	Cum. fluid prod. (ml)	Inst. fluid prod. rate (ml/s)
6	10	2.02	99	99	0.28
10	16.67	1.78	99.5	198.5	0.41
14	23.33	-0.51	97.6	296.1	0.41
21	35	-0.91	95	391.1	0.23
31	51.67	-1.78	96.3	487.4	0.16
44	73.33	-1.31	97.8	585.2	0.13
60	100	-0.57	96.5	681.7	0.1
75	125	-0.54	84.6	766.3	0.09

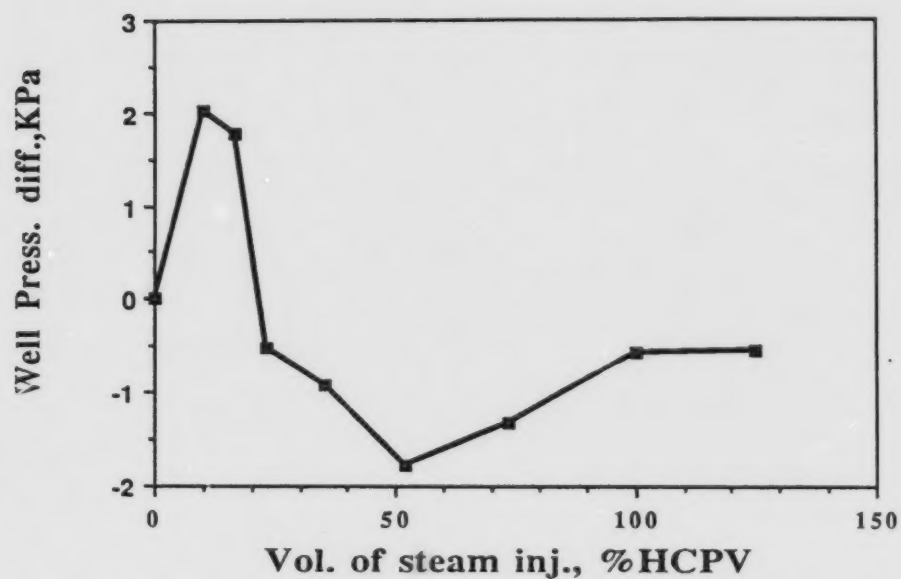


Figure 9.9 : Well press. diff. vs. Vol. of steam inj.
(HP 4)

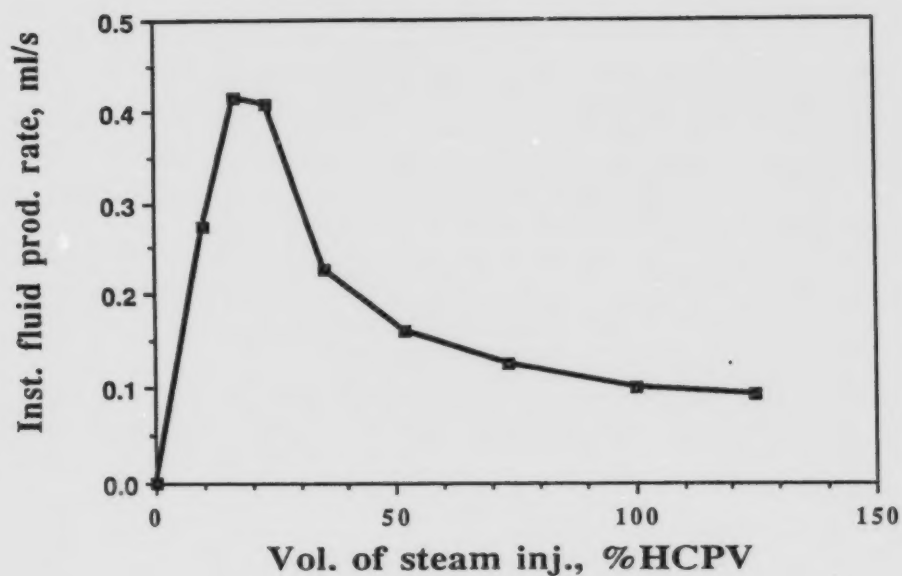


Figure 9.10: Inst. fluid prod. rate vs. Vol. of Steam inj.
(HP 4)

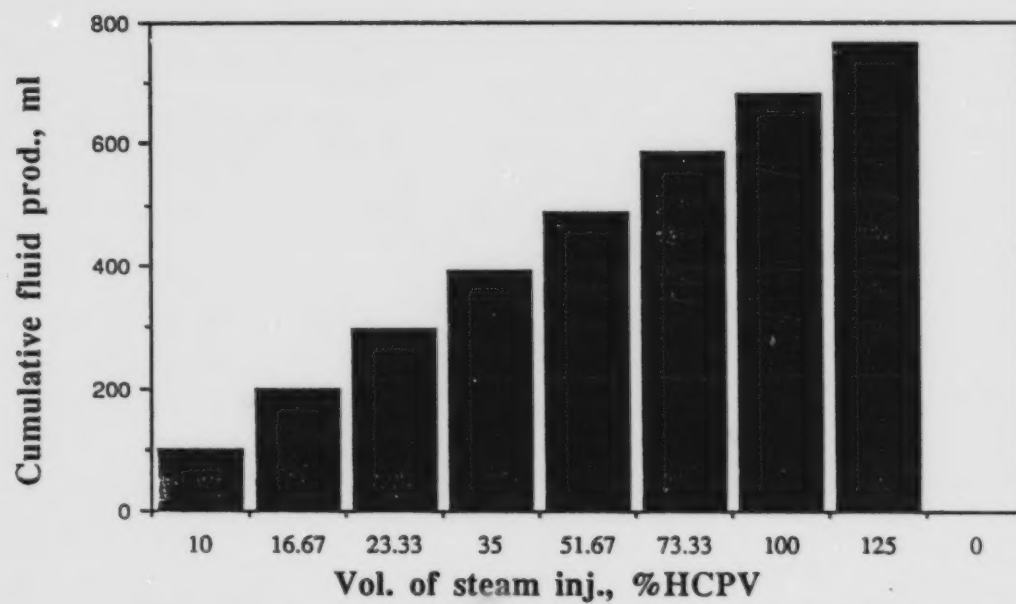


Figure 9.11: Cum fluid prod. vs. Vol. of Steam inj.
(HP 4)

In summary, it can be concluded that the existing equipment are good and adequate for the job. Some improvement could be made to the steam generator to increase its capability to generate higher quality steam at higher pressures and temperatures. The new computer data acquisition system performed smoothly, and free of breakdowns. The current experimental procedure, including the porous medium preparation process and the actual steam injection, is generally good albeit additional improvements—such as the one mentioned above—could be and would be introduced.

Chapter 10

Numerical Simulation

Introduction

Work on simulator development as well as numerical simulations of specific situations were continued during this phase of the project. The simulations were reported in the three papers presented, entitled, "Effect of Bottom and Top Water on Cyclic Steam Stimulation Response", "Role of Foam, Non-Newtonian Flow, and Thermal Upgrading in Steam Injection", and "Effect of Wellbore Steam Quality Variation on Steamflooding Thick Formations" which are included in Appendix I.

Numerical simulation of experiments performed was attempted using a three-dimensional steam injection simulator modified to suit steam injection experiments where bottom water is present. This was not part of the work plan, but it was considered advisable to initiate some work in this direction for the next phase of this project.

Simulator Development

In Phase II of this project, we carried out extensive simulations of steam stimulation and steamflooding under a variety of situations, both in the absence and presence of bottom water. For this purpose we modified our existing steam injection simulator. At the same time, we initiated work on a new six-component, three-dimensional steam injection simulator, incorporating many new features. The governing equations and details of program development were given in the Phase II report submitted previously. One of the difficulties with this simulator has been the excessive amount of computer time needed for each run. We have tried to use two different computer systems (HP 1600 series and Sun 3/160) for this purpose. But we find that these are too slow for computational runs as well as program development. We have therefore been using Amdahl 8086 for this purpose, machine time on which is very limited, and beyond a certain limit (about 80 minutes per year) must be paid at an exorbitant rate. We are considering other options, including the

new Sun or IBM systems, if we can obtain additional funding from other sources. As a result, the computational work involving sensitivity studies has been limited to the runs needed for the above mentioned papers.

Work continued in this phase of the project on improving the solution scheme of the simulator mentioned previously. There are several problems with this simulator. One of these involves a more comprehensive treatment of the injection/production wells and the simulation of foam. The other one is the development of the Jacobian for the fully implicit solution. For this purpose, we are adding the numerical calculation of derivatives, which should be considerably faster, though less accurate than the present analytical approach. Thus the work in progress involves implementation of these three improvements in the simulator under development.

Numerical Simulations of Steam Injection Situations

During Phase III, we carried out a number of simulation studies involving (i) steam quality changes in the wellbore coupled with our modified three-dimensional simulator, and (ii) effect of top water on steam injection. The results of these simulations were used in two of the papers cited in the introduction. The papers may be referred for details. The highlights of the results are summarized below.

Effect of Bottom and Top Water on Cyclic Steam Stimulation and Steamflood Response

In several fields, a high water saturation zone occurs above the oil zone, in communication with it. It is important to examine the geology of such setting, and have good rock and fluid data variable. In some instances, the water-saturated rock is fine grained, indicating that a different set of capillary pressure and relative permeability curves should be employed. The several situations conducted in this study merely point out salient effects. Figure 10.1 shows bar charts, with each pair of bars representing a different

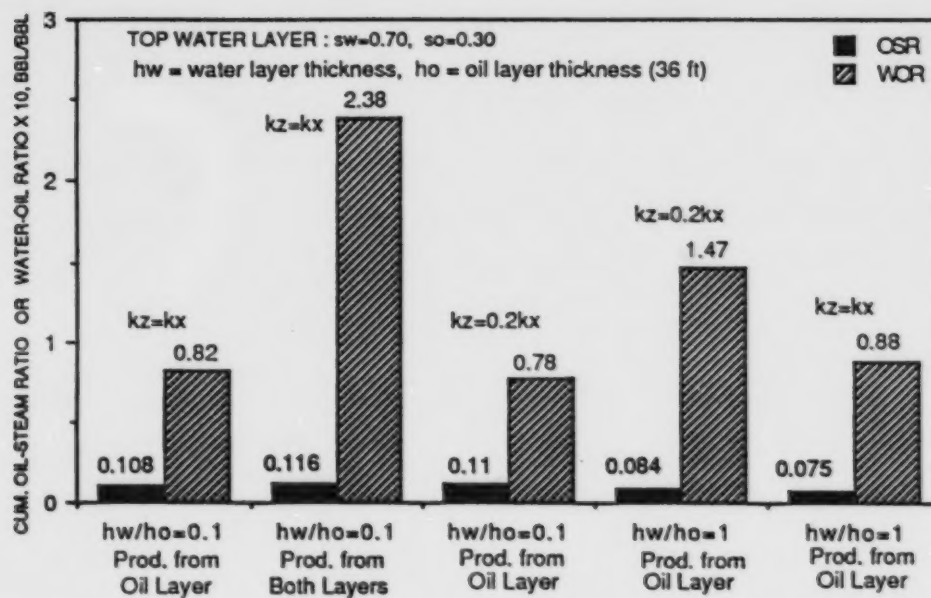


Fig. 10.1: First Cycle, Cumulative Steam-Oil and Water-Oil Ratios, for Various Operating Conditions. Injection into the (Bottom) Oil Layer Only.

combination of water-to-oil zone thickness ratio and the ratio of the vertical to horizontal permeabilities. The absolute permeabilities, relative permeabilities and capillary pressure characteristics were the same for the two layers. It was assumed that only the oil zone was perforated in all cases, except in one instance the water zone was also opened for production only.

The high conductivity water zone overlying the oil zone leads to early channelling of steam into the water zone, aggravated by gravity segregation. At a later stage, the steam entering the oil zone also migrates upwards, driving a substantial amount of oil into the well blocks directly above the injection blocks. The top water layer gets heated to nearly the steam temperature in a relatively short time. Figure 10.1 shows that the oil-steam ratios in the five cases considered were of the order of 0.1. These cases correspond to combinations of water-to-oil thickness ratios of 0.1 and 1.0, and vertical permeability ratios of 1.0 and 0.2. In one case, the water layer was also produced in the production phase. The water-oil ratio was the highest in this case. Although some of the migrated oil was produced, much water had to be produced as a result. It is interesting to note that the vertical permeability ratio appears to be much less important than the top water thickness ratio. This trend was also noticed in the case of bottom water. The above simulation results show the dominant features of top water. On the whole top water appears to be even more undesirable than bottom water, in view of migration of oil into the water zone above.

Effect of Wellbore Steam Quality on Steamflood Response

Given a wellbore model, such as the one developed in this work, it is possible to carry out a wide variety of coupled wellbore reservoir studies. Several runs of this type were conducted to illustrate the effect of time and depth dependent steam pressure and quality on oil recover, as compared to oil recovery based upon uniform values. The steam injection simulator developed was coupled with the wellbore model. The simulator is a

three-phase, three-dimensional fully implicit black oil type steam model, and utilizes a direct solution procedure. It has been extensively tested for many types steam injection processes, including cyclic steaming.

The data used in the simulations refers to the Aberfeldy reservoir in Saskatchewan, which is much thinner (12 m) than the simulated thickness of 100 m, used to bring out the effect of steam quality variation. It is seen that the assumption of a uniform sand face steam pressure and quality leads to an oil recovery of 42% which is considerably higher than the value of 28%, for the more realistic case of variable pressure and quality. The main reason is that in the variable case, wetter steam is being injected into the lower part of the formation. At the same time, the pressure is higher, and thus more hot condensate is going into the lower zone. This tends to promote early steam override, as the temperature and steam saturation distributions showed.

Figure 10.2 summarizes the results for two steam injection rates (100 and 300 m³/day) and several formation thickness (16 to 100 m) for the two cases, viz. uniform steam quality over the entire interval, and steam splitting so that steam pressure and quality vary with time over the two halves of the formation. The oil recoveries shown are for the same amount of steam injected in terms of pore volume. It is seen that the oil recoveries vary considerably between the two cases considered, i.e. uniform and varying steam conditions. For a given injection rate, the oil recovery differs more at a larger formation thickness, because of the greater variation in steam pressure and quality over thick intervals. Also, the difference in the oil recoveries for the two cases is smaller at the higher rate, because of the smaller drop in quality from the offtake point to the total depth. Although these results are for specific conditions, they do show the importance of steam pressure and quality in relation to oil recovery computations.

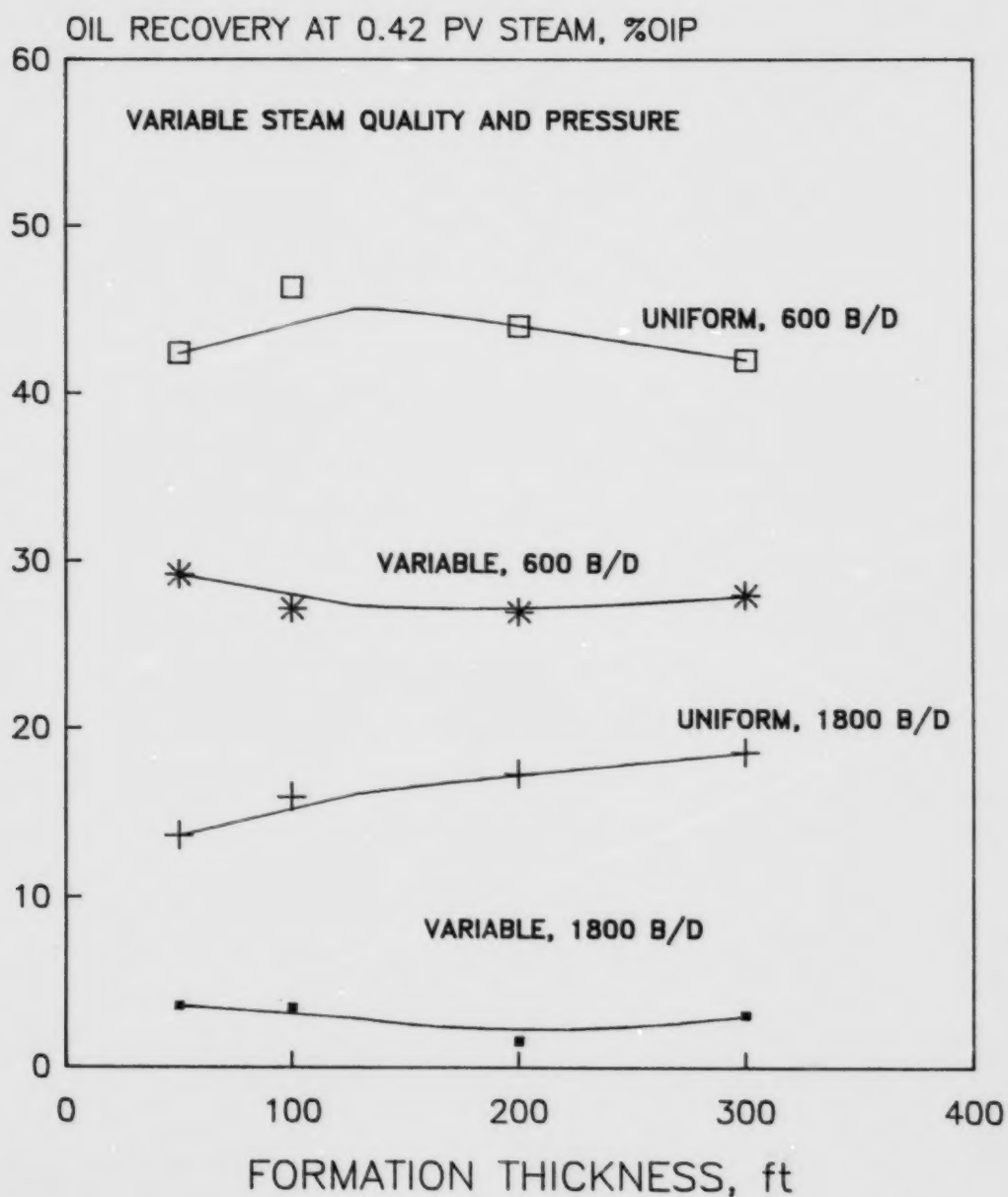


Fig. 10.2: Oil recovery as a function of formation thickness and steam injection rate.

Concluding Remarks

The previously developed simulator was modified during Phase III and work is still continuing on adding several improvements to speed it up. A number of simulations were carried out for the three papers presented. Of these, the simulations involving "top water" generated a great deal of interest, since such occurrences of water — above the pay zone — proved to be even more detrimental than bottom water. (Top water has been reported in a number of Athabasca formations). Work on simulator development as well as simulation studies including history matching of laboratory experiments will continue through Phase IV.

Chapter 11

Conclusions

Based upon the results of this research the following conclusions were reached:

1. The solvent-steamflood process exhibits an improved oil recovery capability from a bottom water formation as compared to a conventional steamflood in the same type of reservoir. The higher recovery of the solvent-steamflood was due to the solvent slug channelling into the oil region away from the bottom water, allowing the steam to penetrate the oil zone more easily. This increased the stability of the steam displacement of oil and resulted in more oil being mobilized and subsequently recovered.
2. (i) The implementation of gas injection prior to a steamflood of a thin formation with underlying water appears to improve oil recovery, compared to a conventional steamflood, by partially diverting the injected steam away from the bottom water zone and increasing the steam injectivity in the oil zone. The solvent-steamflood method yields the highest oil recovery compared to injecting gas prior to the steamflood of a bottom water formation.
- (ii) Gas injection prior to a solvent-steamflood in a bottom water formation tends to diminish solvent channelling in the oil, due to the solvent travelling over top of the oil zone. This results in less steam penetrating the oil layer. Consequently, less oil is mobilized by the steam causing a drop in oil recovery of a solvent-steamflood as compared to its implementation in a heavy oil formation with underlying water but without a gas cap or gas channel.

3. Bottom water has detrimental effects in the thermal and sweep efficiencies of a steamflood, and as the bottom water thickness increases the loss of the steam to the underlying water correspondingly increases.
4. In the case of a solvent-steamflood process on a bottom water formation, as the bottom water thickness increased in the model, the oil recovery decreased until a limiting bottom water thickness was reached. Above this value the use of a solvent would not significantly improve oil recovery. The bottom water thickness above which improved oil recovery by a solvent-steamflood is negligible was estimated to be somewhere between 25% and 30% of the total formation thickness.
5. There exists an optimal solvent slug size of approximately 10% of the model pore volume which maximizes the amount of oil recovered by a solvent-steamflood process.
6. Location of the injection interval in the upper portion of the formation (ie. oil zone) permits more efficient use of the injected solvent and steam and increases oil recovery by directing the fluids into the oil zone and away from the bottom water layer, as compared to injection over the entire interval or into the bottom portion of the formation.
7. The use of a partial bottom water barrier in combination with a steamflood of a bottom water formation helped to prevent steam from travelling directly into the water zone so it could more efficiently heat and mobilize the overlying oil zone.
8. Conducting solvent-steamfloods of previously waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery scheme.

9. A comparison of the experimental results for a solvent-steamflood, conventional steamflood, gas injection prior to a steamflood or solvent-steamflood and a partial bottom water barrier method all conducted in a bottom water model, shows that the solvent-steamflood technique yielded the highest oil recovery.
10. An analysis of formation heating for a conventional steamflood of a homogeneous, oil-saturated model (Run 26) was carried out using classical methods. It is concluded that:
 - (i) The Mandl-Volek steam injection model provides the best representation of steam zone development in the model compared to the Marx-Langenheim and Lauwerier theories. This indicates that the latent heat injection rate fell below the consumption rate needed for continued steam zone advance.
 - (ii) The heat loss from the model was considerable, which is typical of steam injection processes in thin reservoirs. Results indicate that approximately one quarter of the total heat injected remained in the model to be used to mobilize the in-place oil.
11. Visual models proved to be a good adjunct to the overall work of studying horizontal wellbore flow mechanics. Despite their unscaled nature, they did provide information on the fluid flow patterns in the vicinity of a horizontal wellbore, as well as showed that a horizontal well could be a good injector for suitably low injection rates.
12. The experiments carried out using the high-pressure model showed that there was a strong correlation between the pressure loss across the horizontal wellbore and fluid production rate, especially in the early production periods.

13. Computer simulation is an effective means for comparing the relative merits of different horizontal and vertical well combinations.

Chapter 12

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Appendix A

Temperature Profiles

Figure A.1 : Run 39
Steamflood in Bottom Water Model

Temperature Profile for
0.25 Pore Volumes Injected

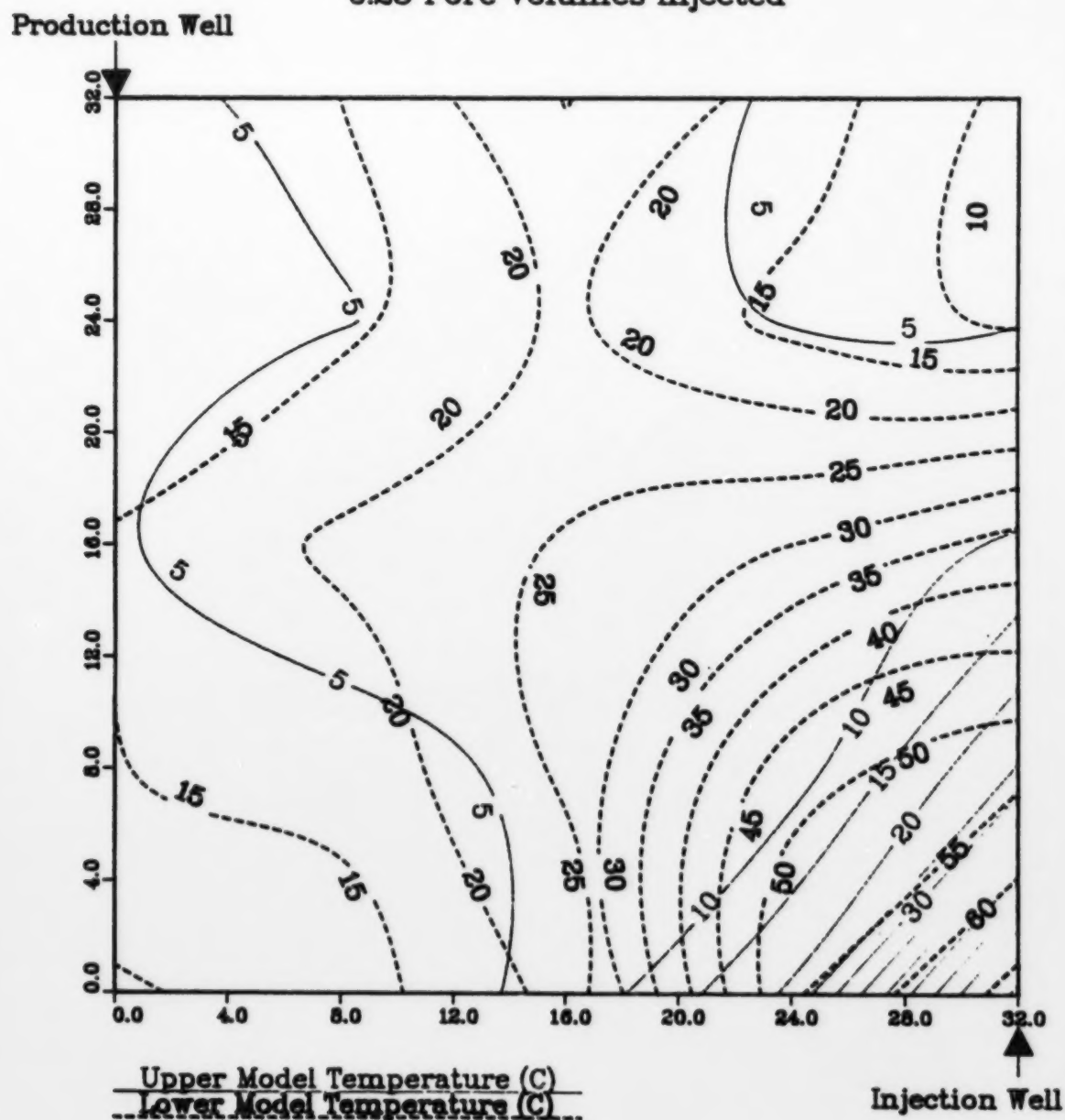
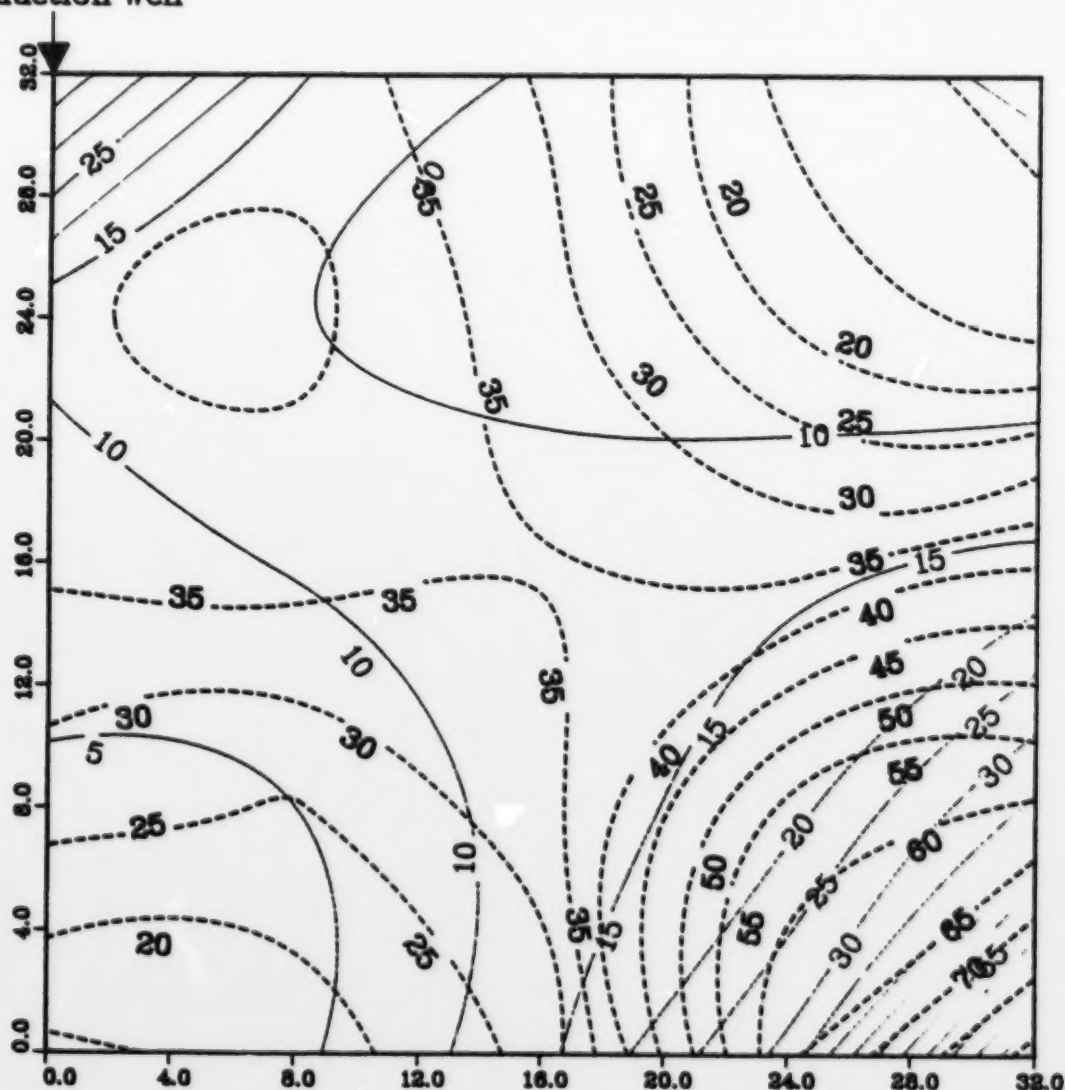


Figure A.2 : Run 39
 Steamflood in Bottom Water Model

Temperature Profile for
 0.50 Pore Volumes Injected

Production Well



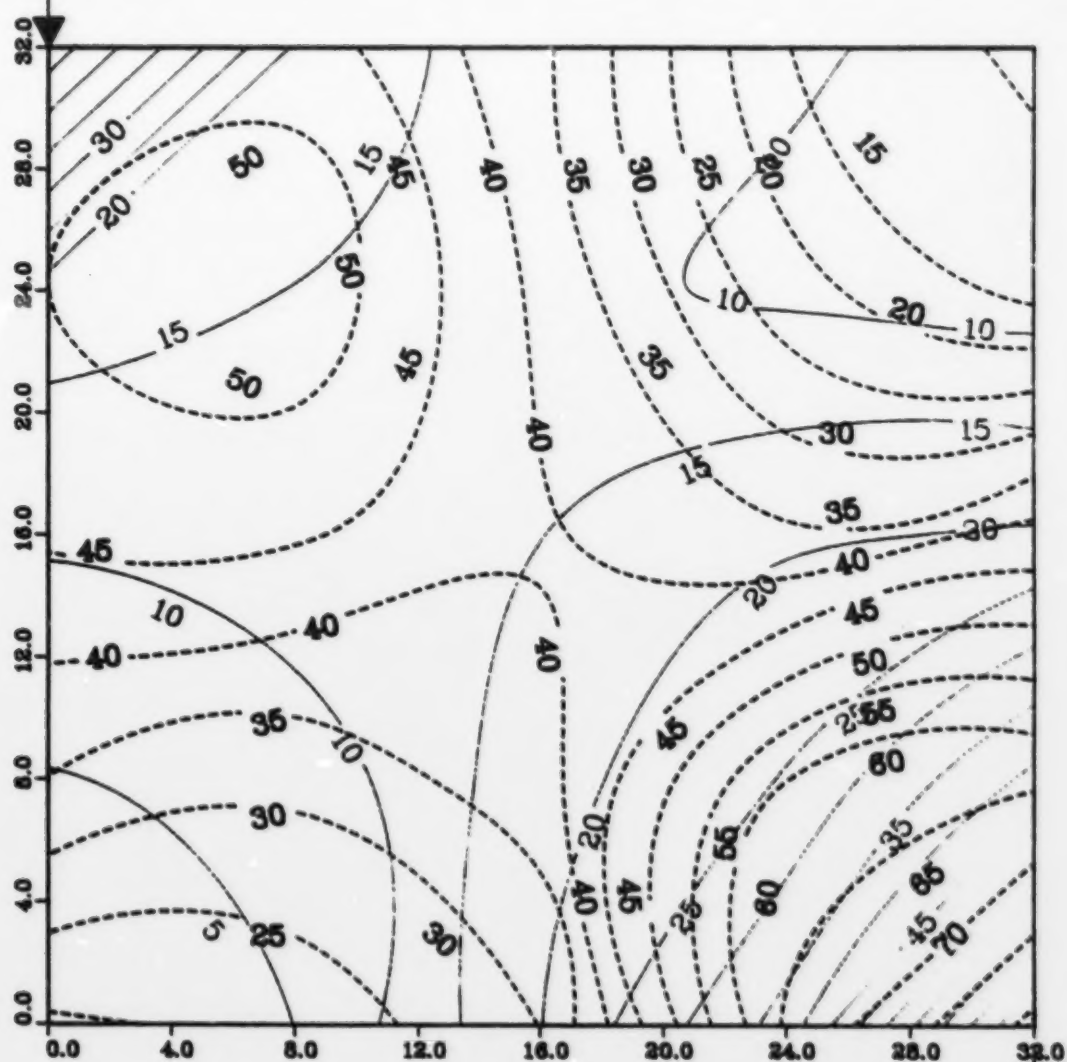
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.3 : Run 39
 Steamflood in Bottom Water Model

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.4 : Run 39
Steamflood in Bottom Water Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

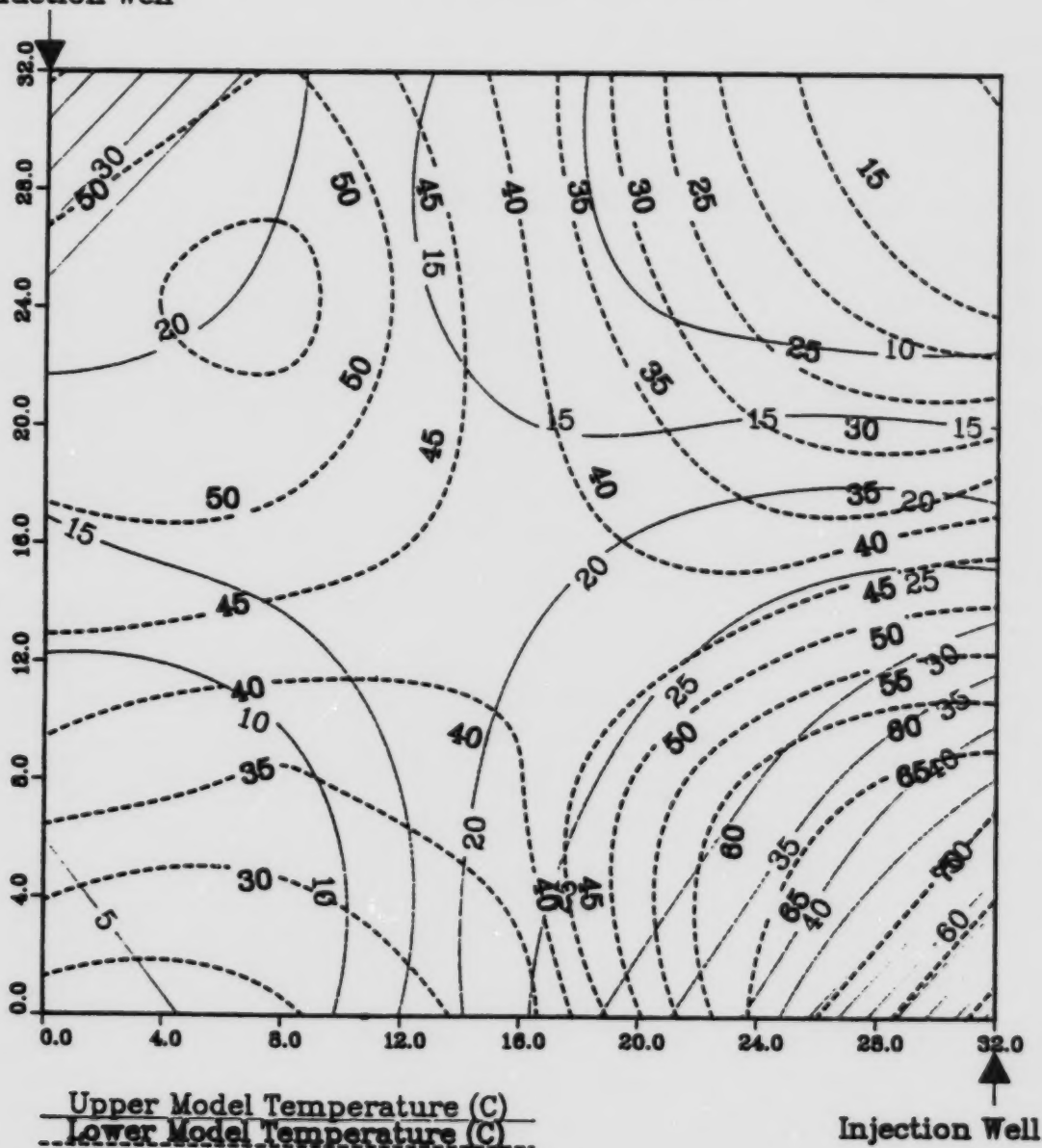
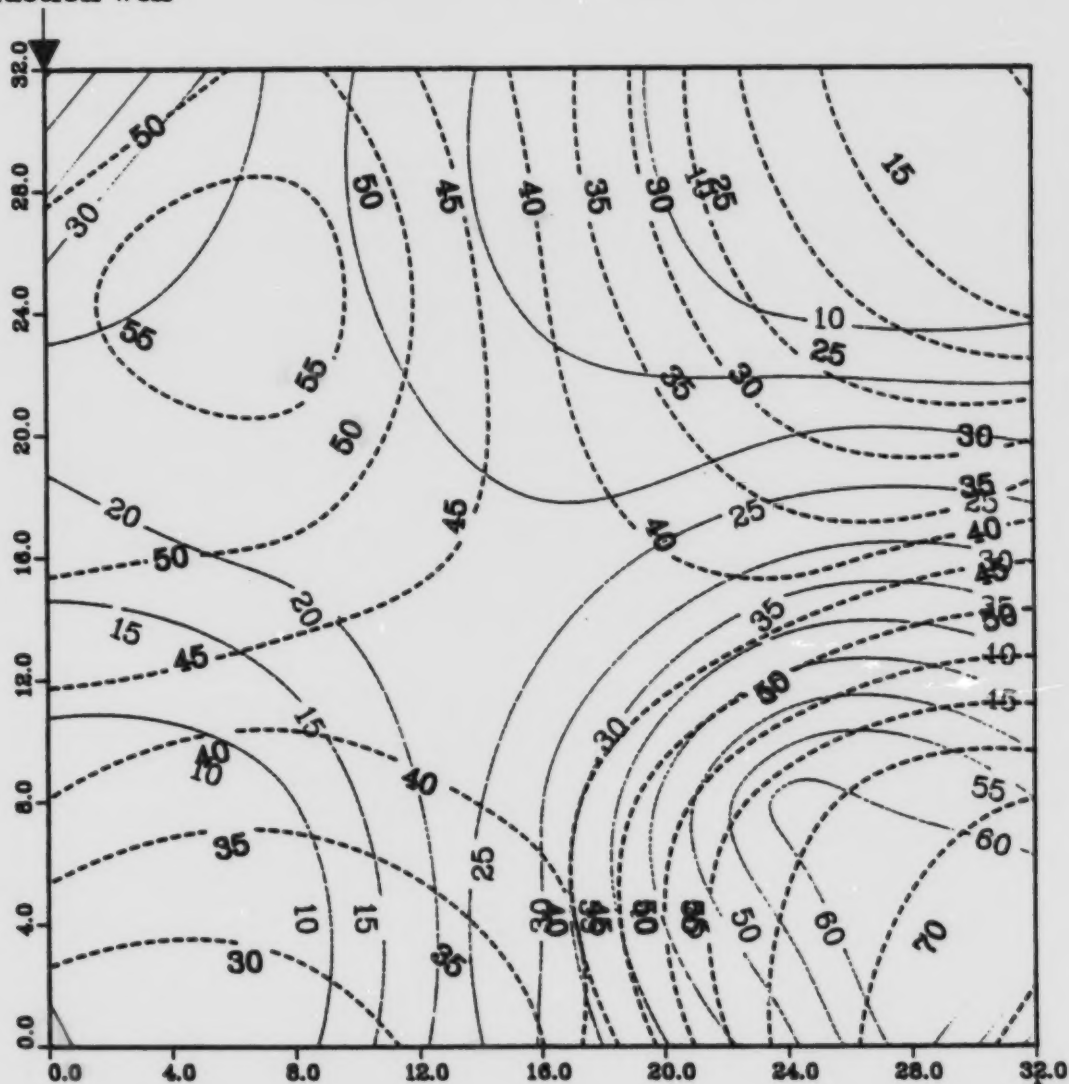


Figure A.5 : Run 39
Steamflood in Bottom Water Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

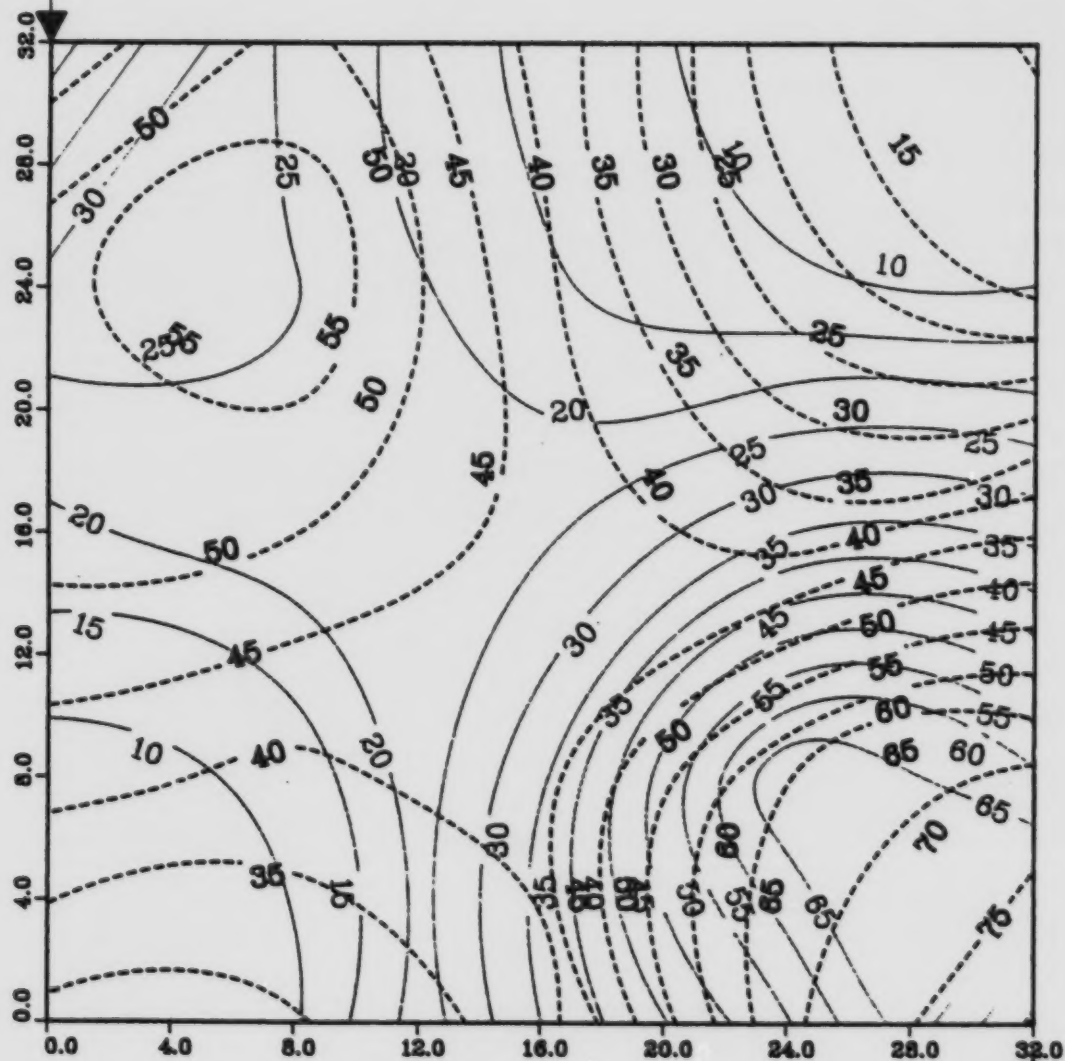
Lower Model Temperature (C)

Injection Well

Figure A.6 : Run 39
Steamflood in Bottom Water Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.7 :Run 39 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

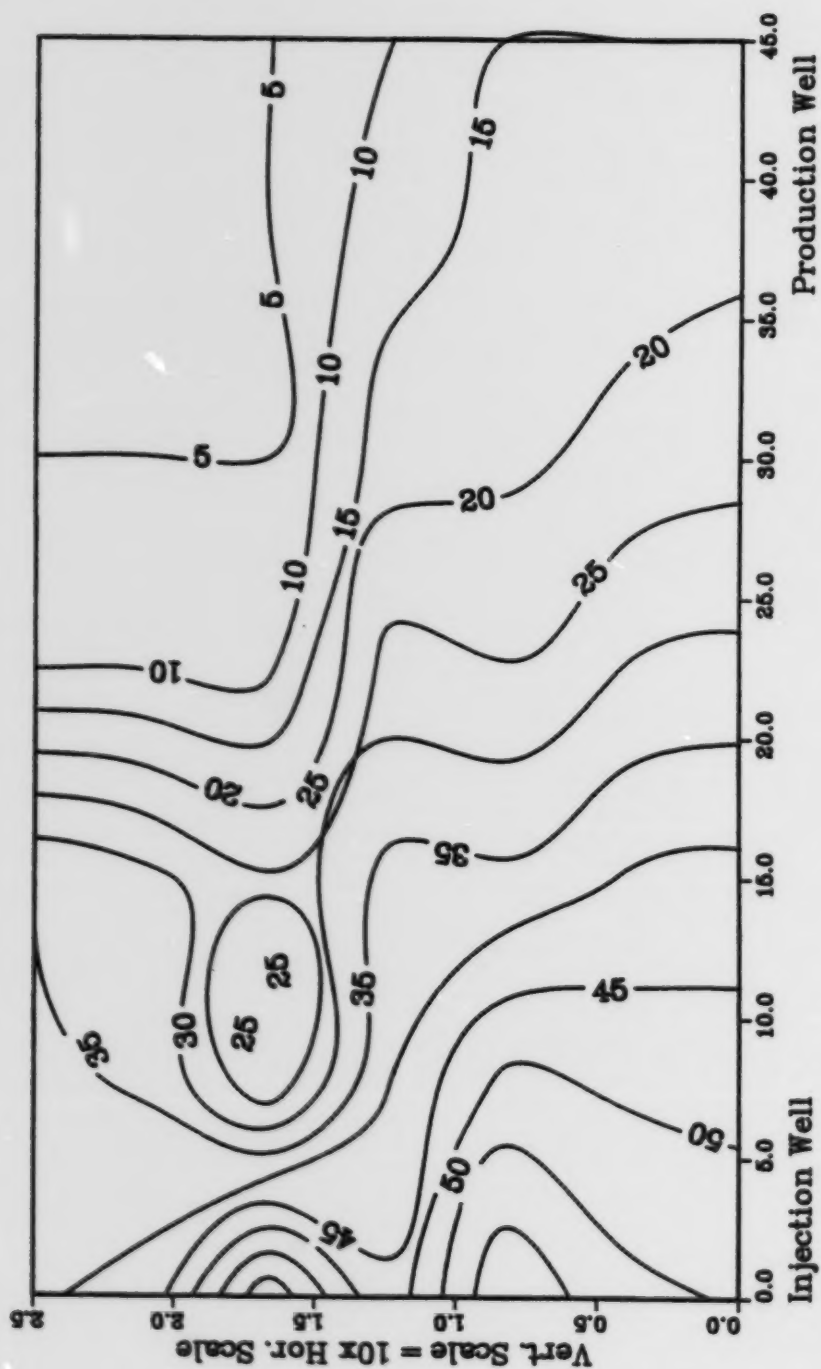


**Figure A.8 :Run 39 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

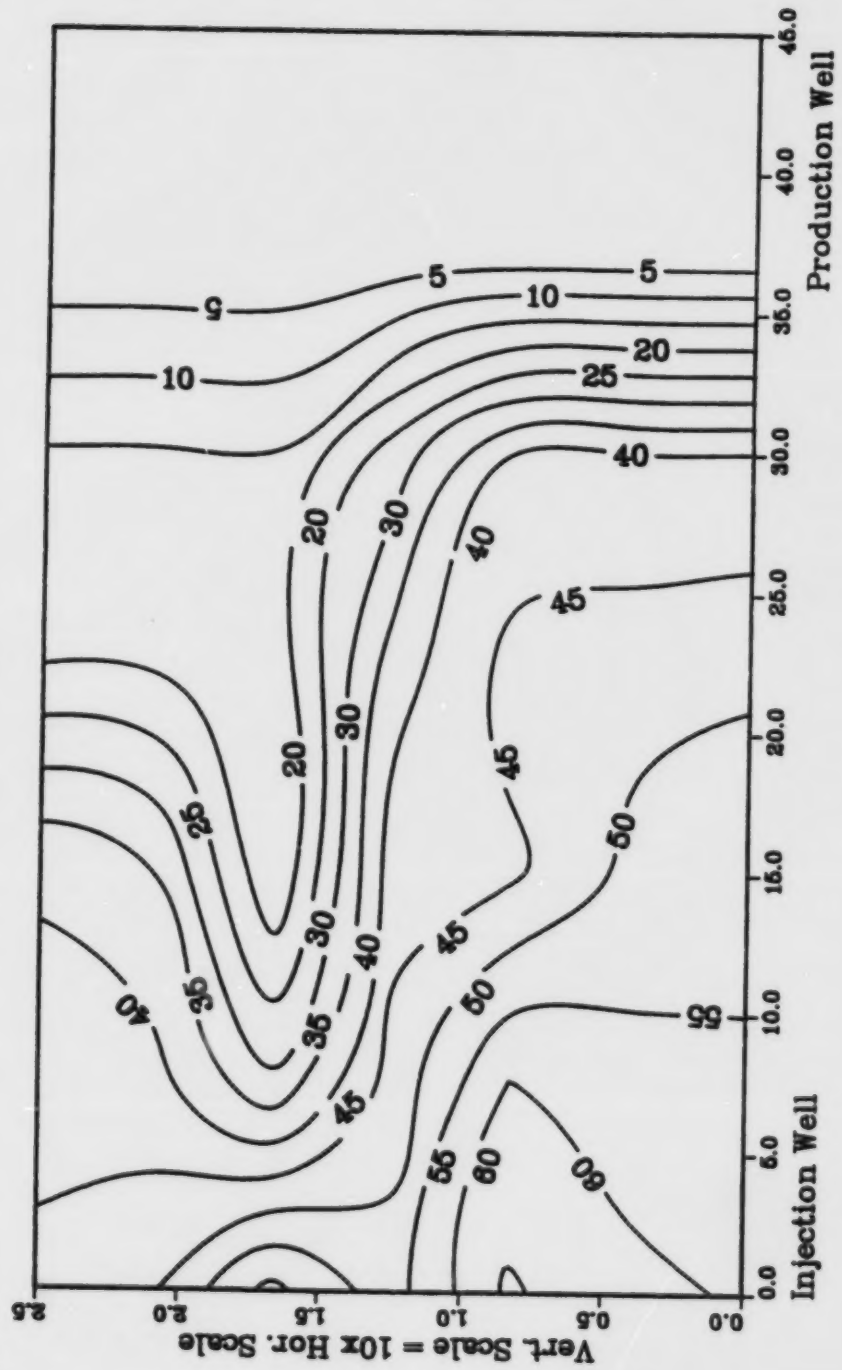


**Figure A.9 :Run 39 Temp Profile
Injector to Producer Cross-Section**
0.76 Pore Volumes Injected.

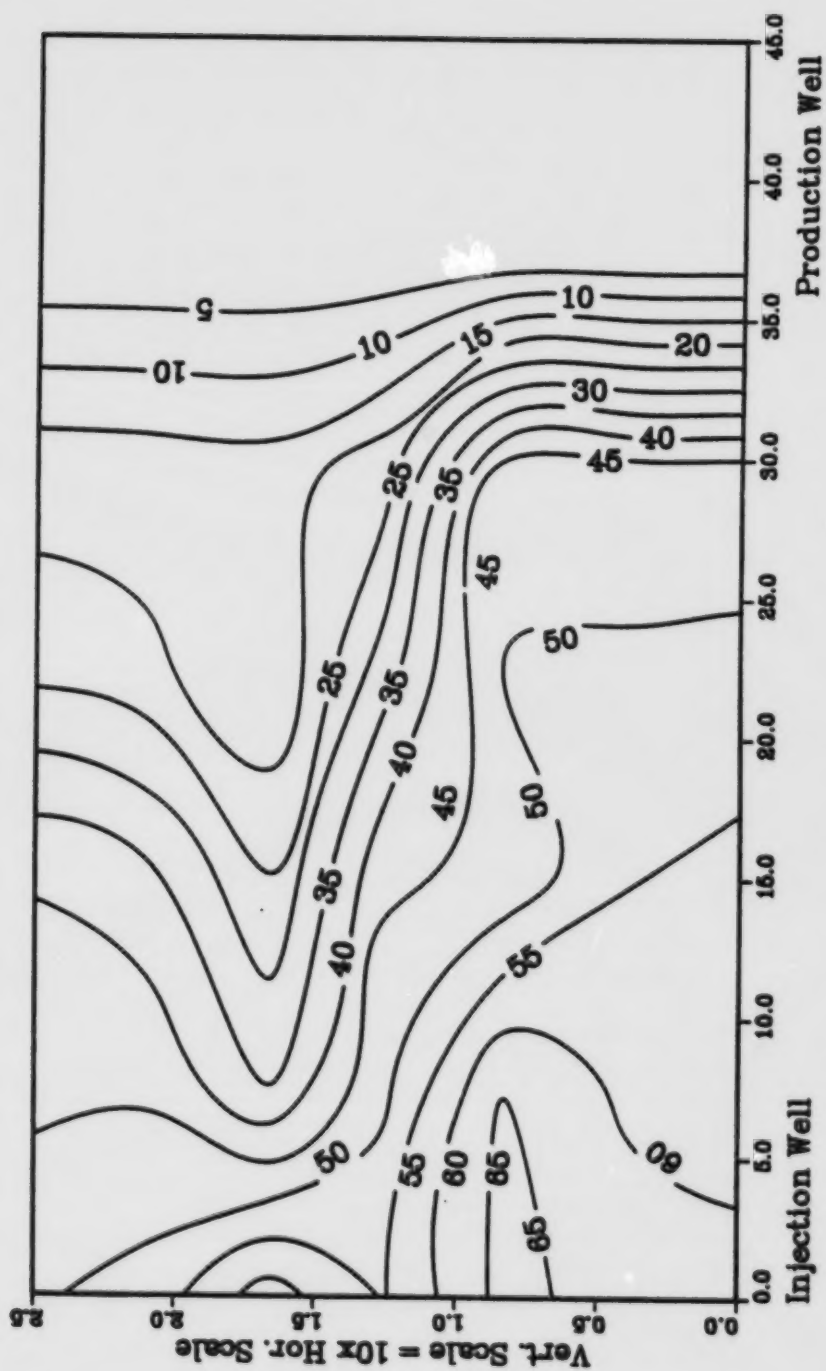


**Figure A.10 :Run 39 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

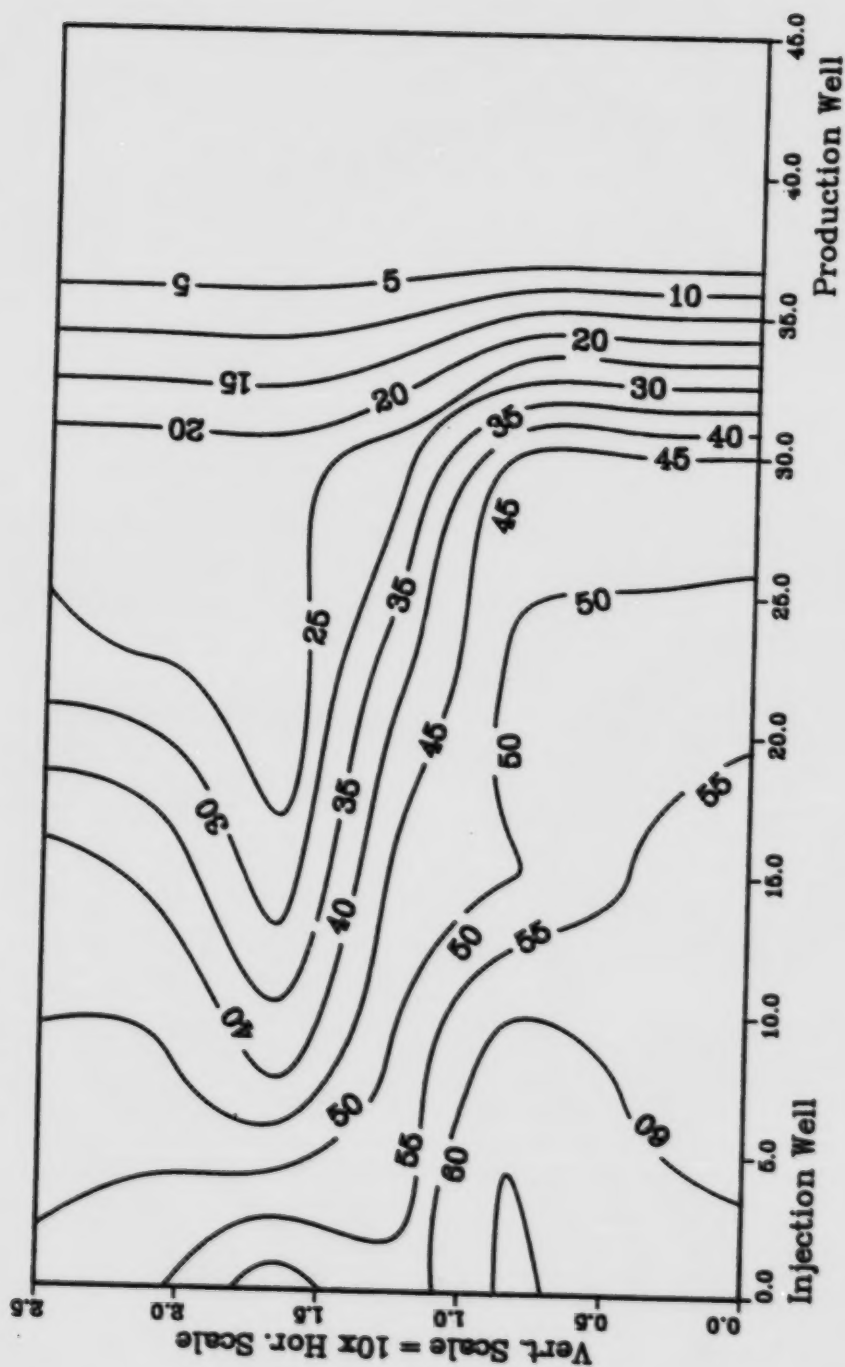
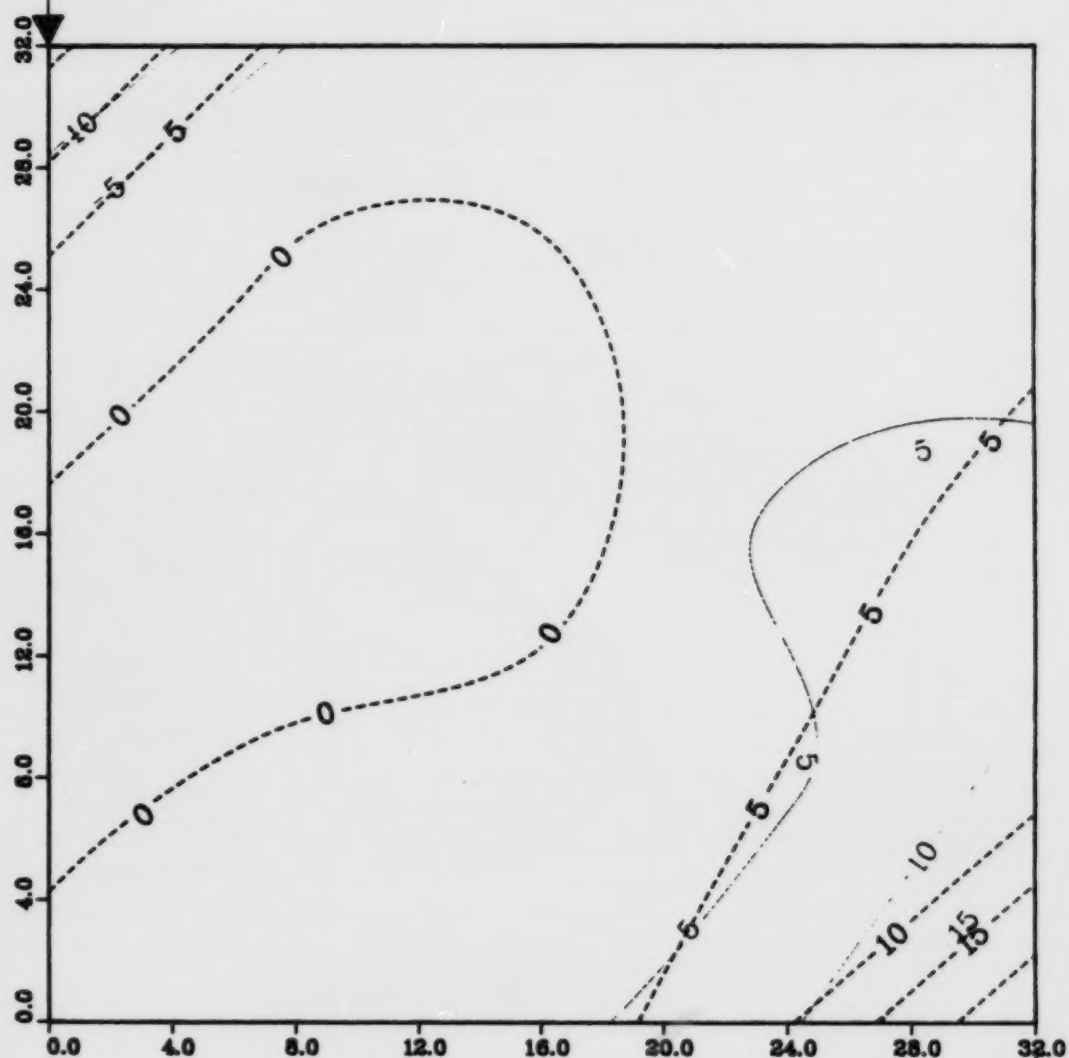


Figure A.11 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



— Upper Model Temperature (C)
--- Lower Model Temperature (C)

Injection Well

Figure A.12 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
0.50 Pore Volumes Injected

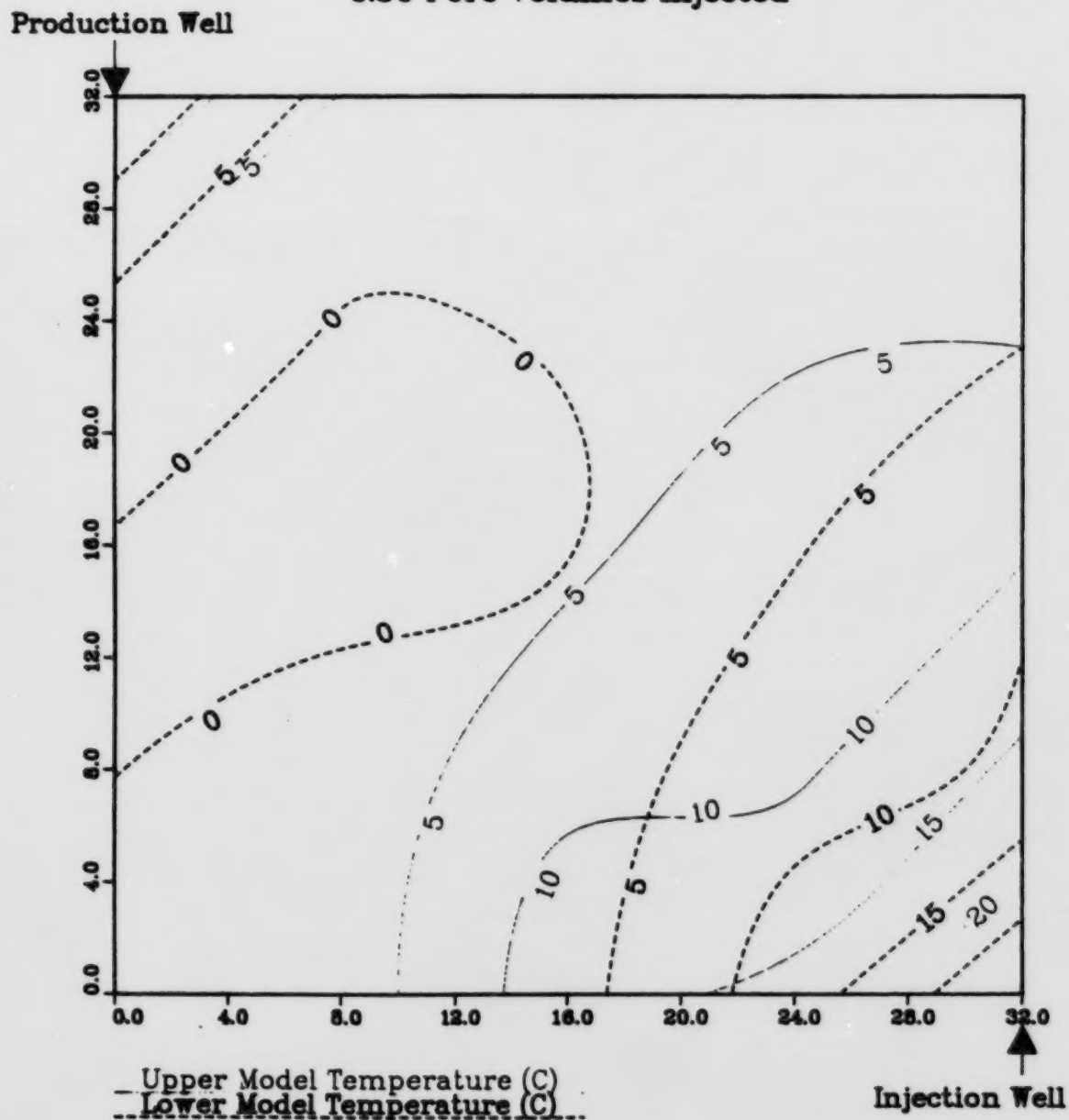
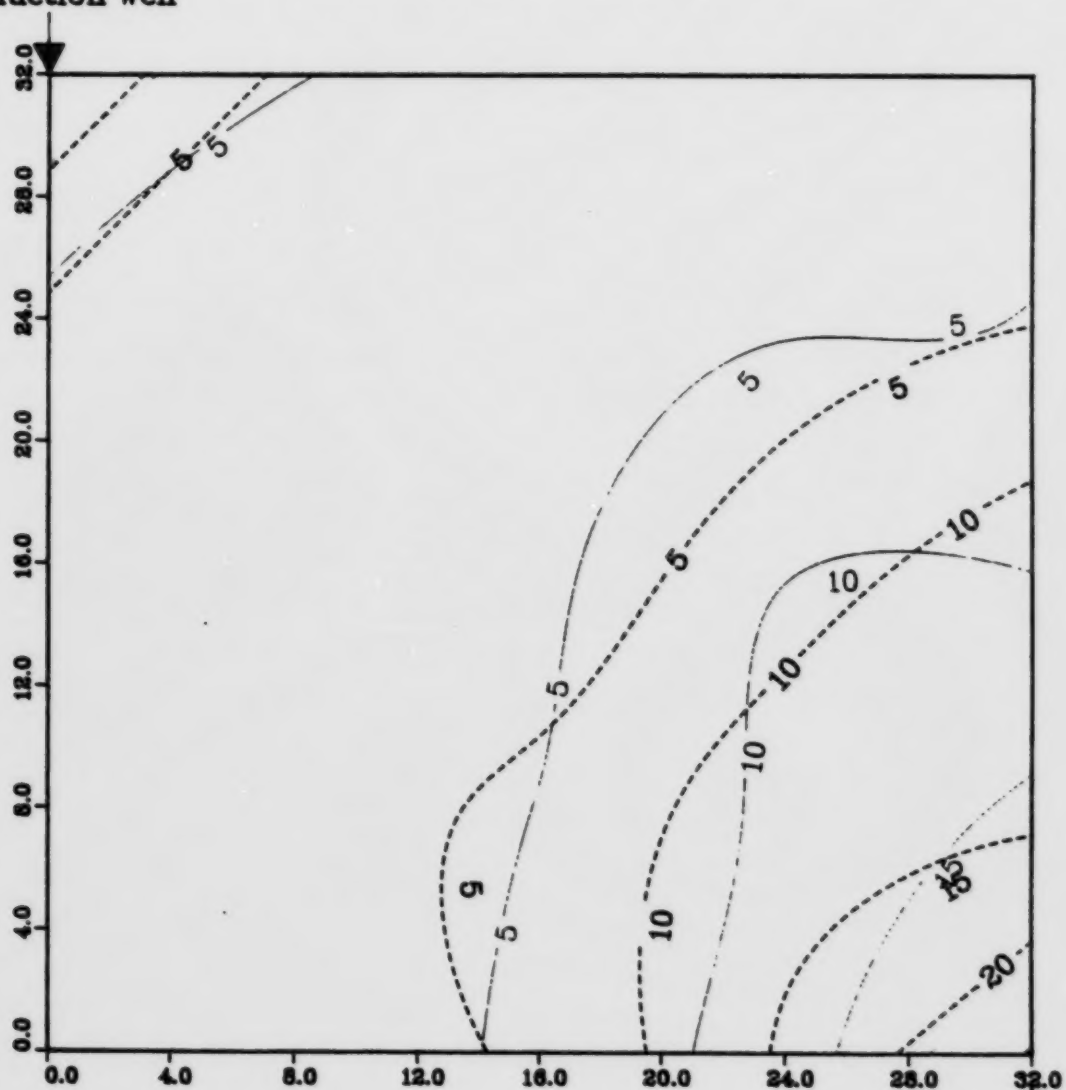


Figure A.13 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



— Upper Model Temperature (C)
- - Lower Model Temperature (C)

Injection Well

Figure A.14 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
1.00 Pore Volumes Injected

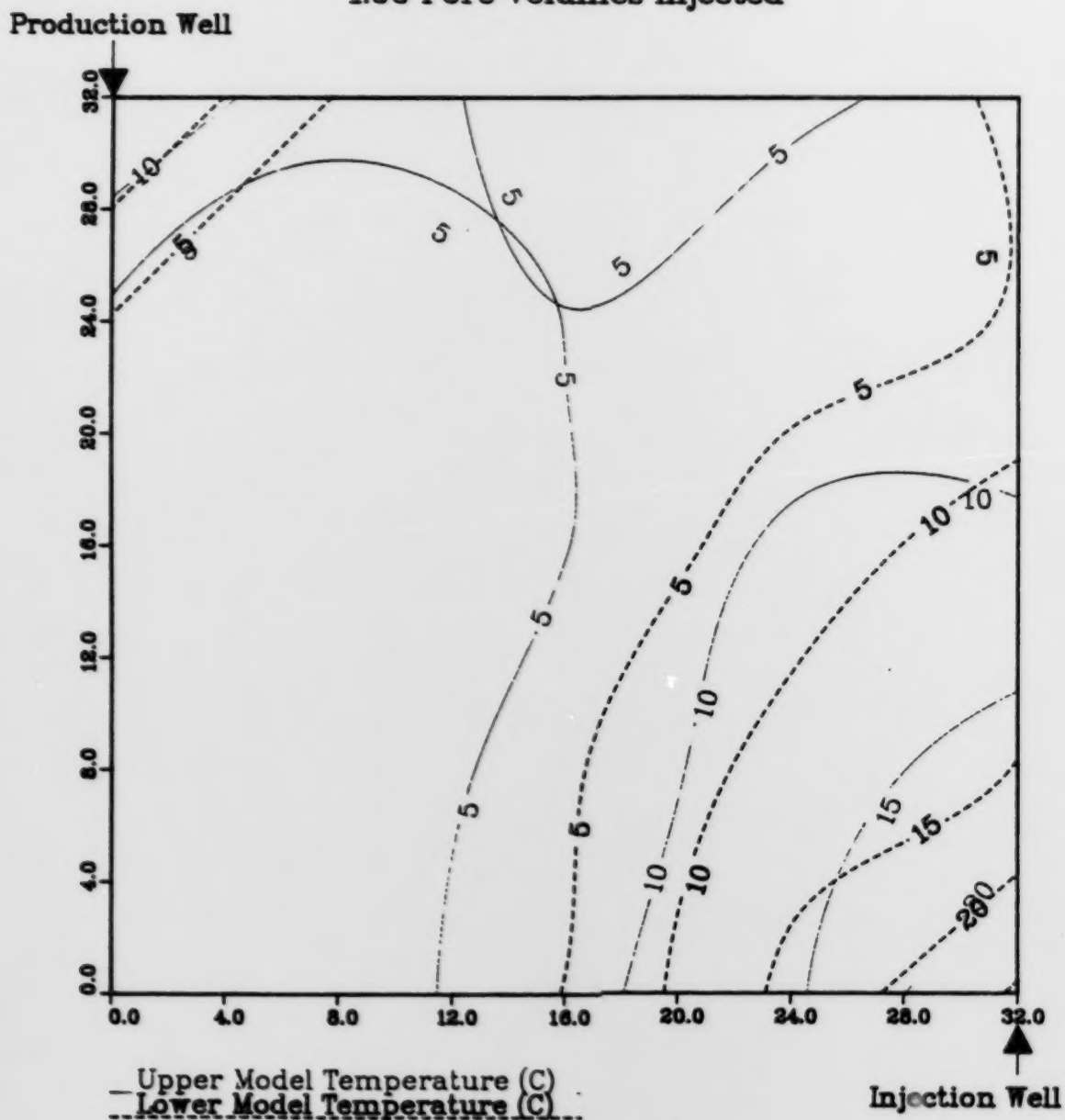


Figure A.15 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
1.25 Pore Volumes Injected

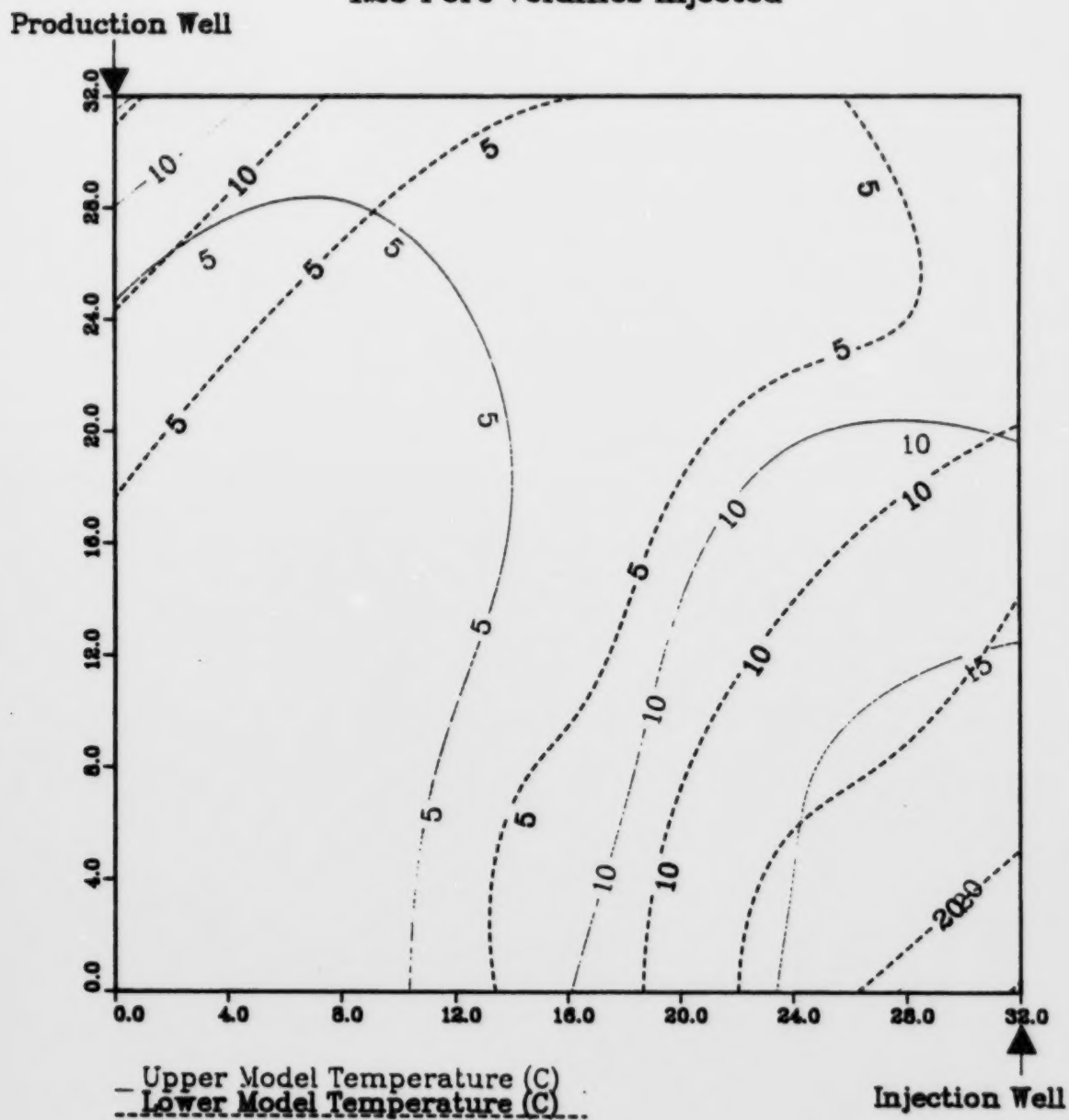


Figure A.16 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
1.50 Pore Volumes Injected

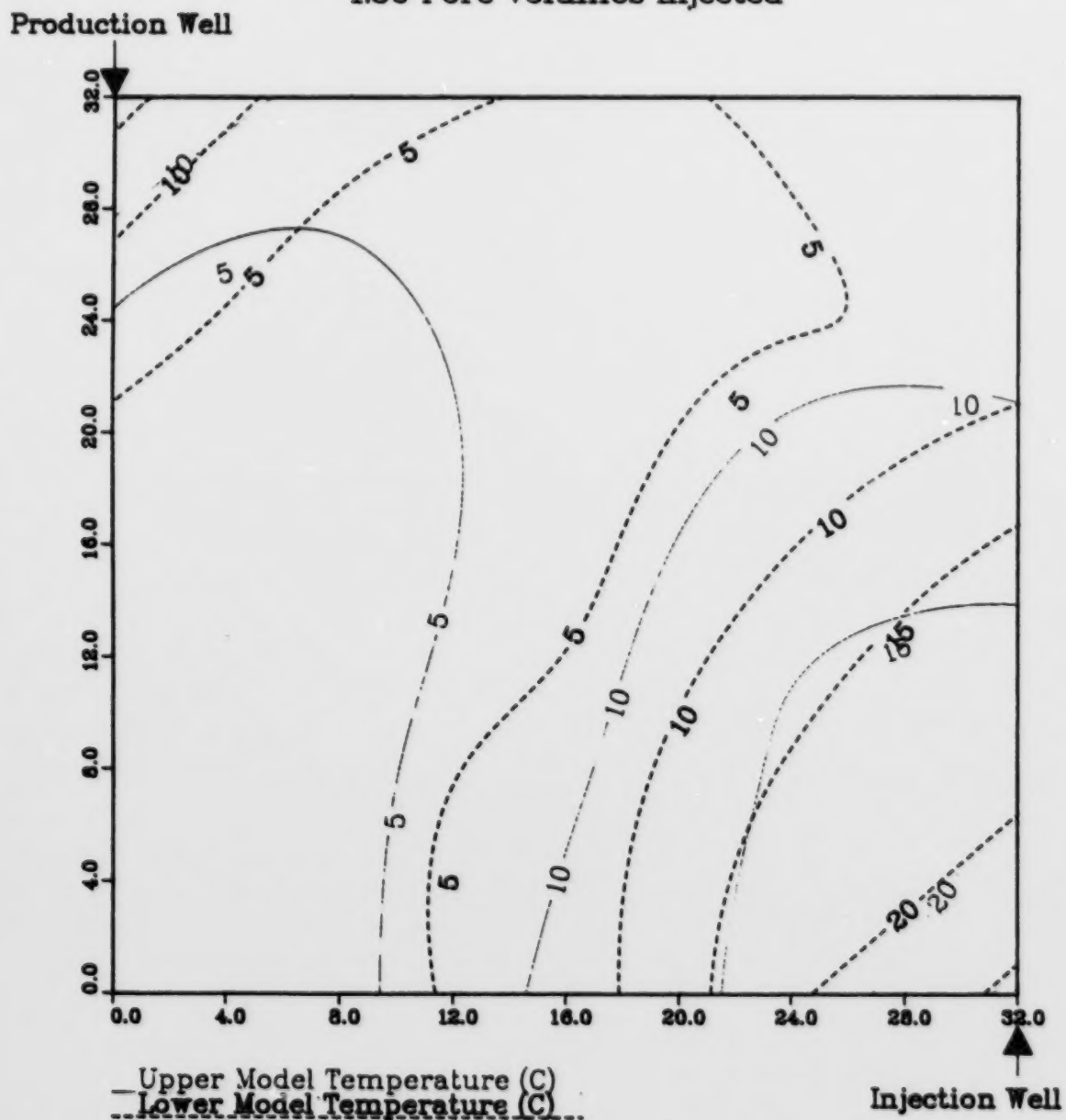


Figure A.17 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
1.75 Pore Volumes Injected

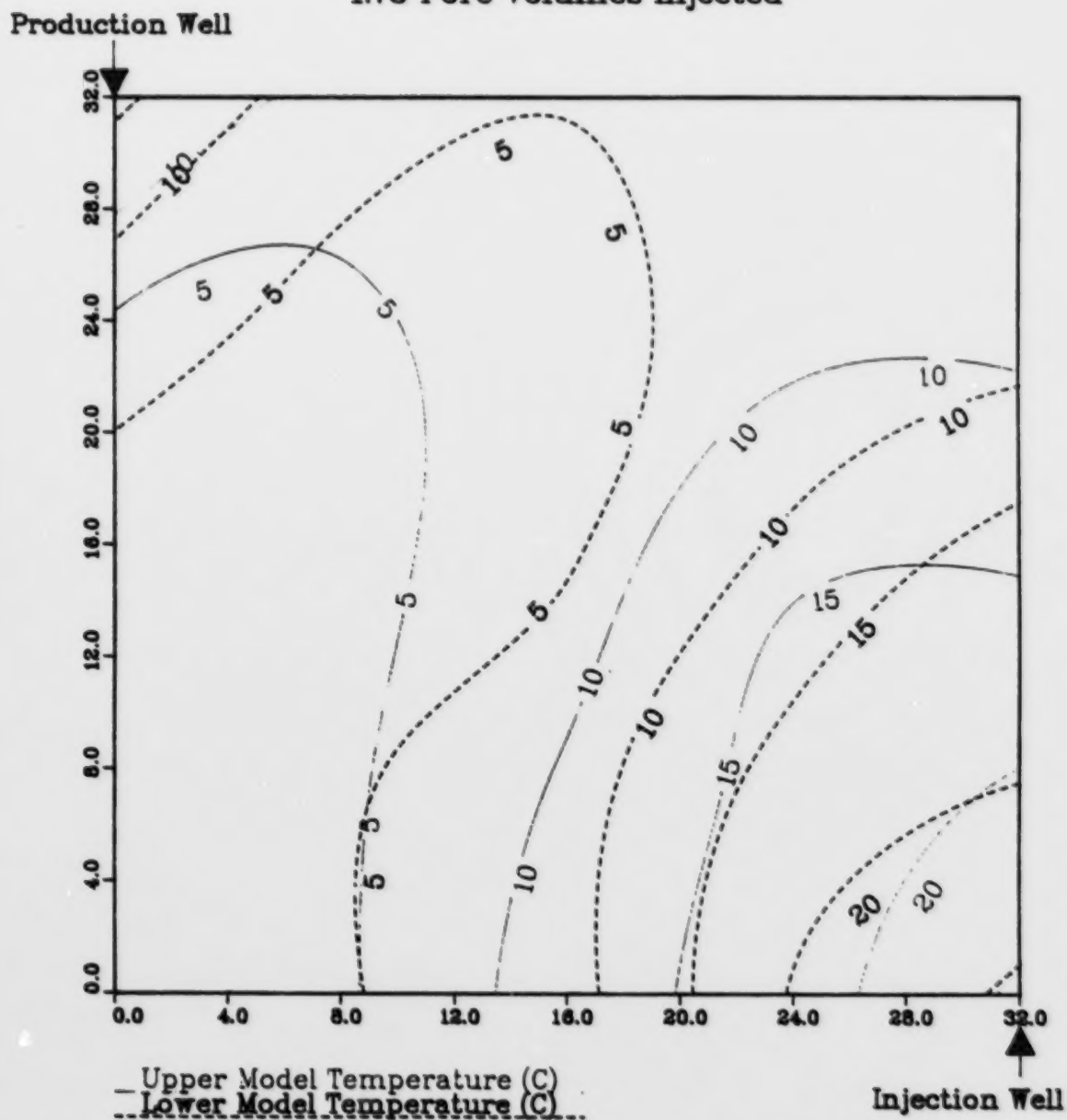
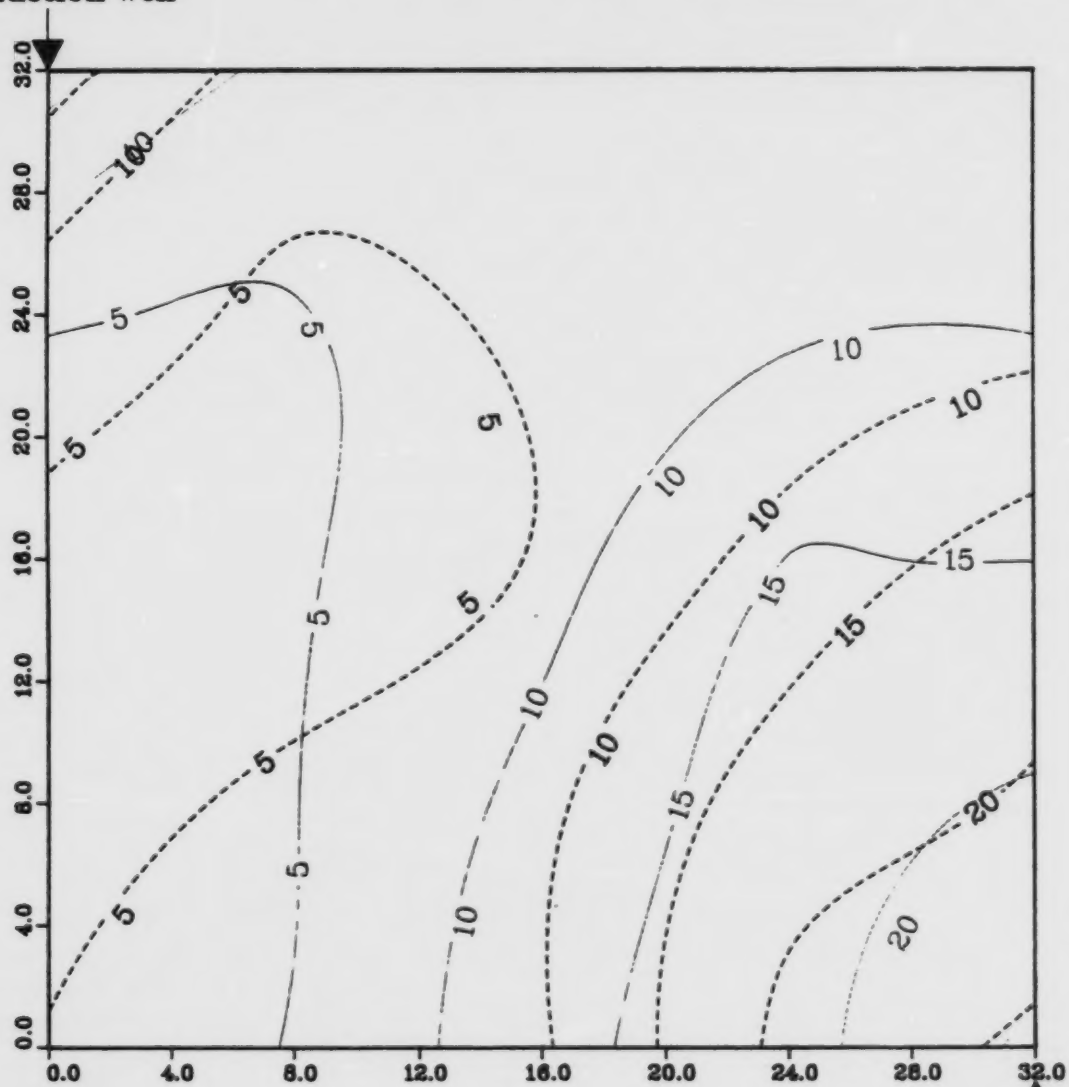


Figure A.18 : Run 40
Solvent Flood in Homogeneous Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



— Upper Model Temperature (C)
--- Lower Model Temperature (C)

Injection Well

**Figure A.19 :Run 40 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

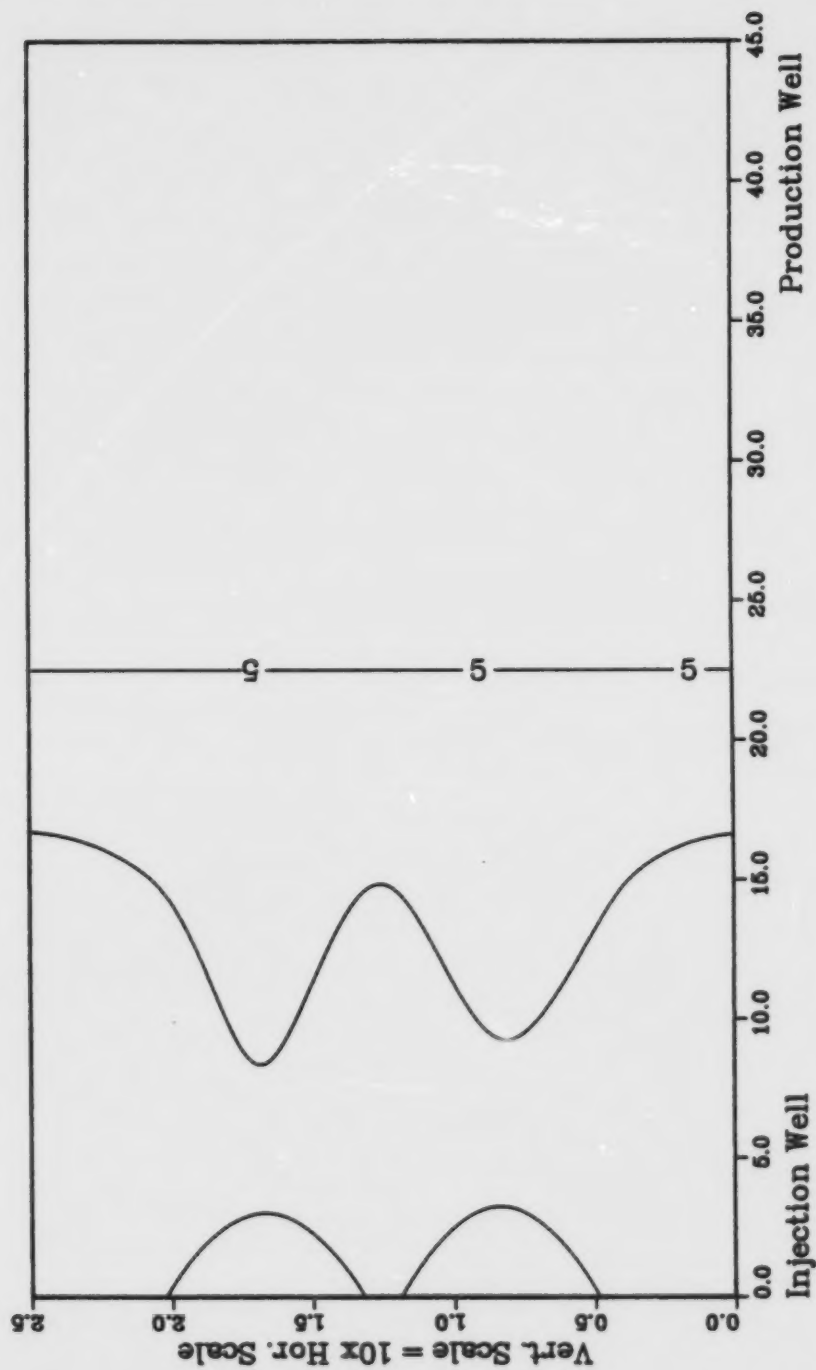


**Figure A.20 :Run 40 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

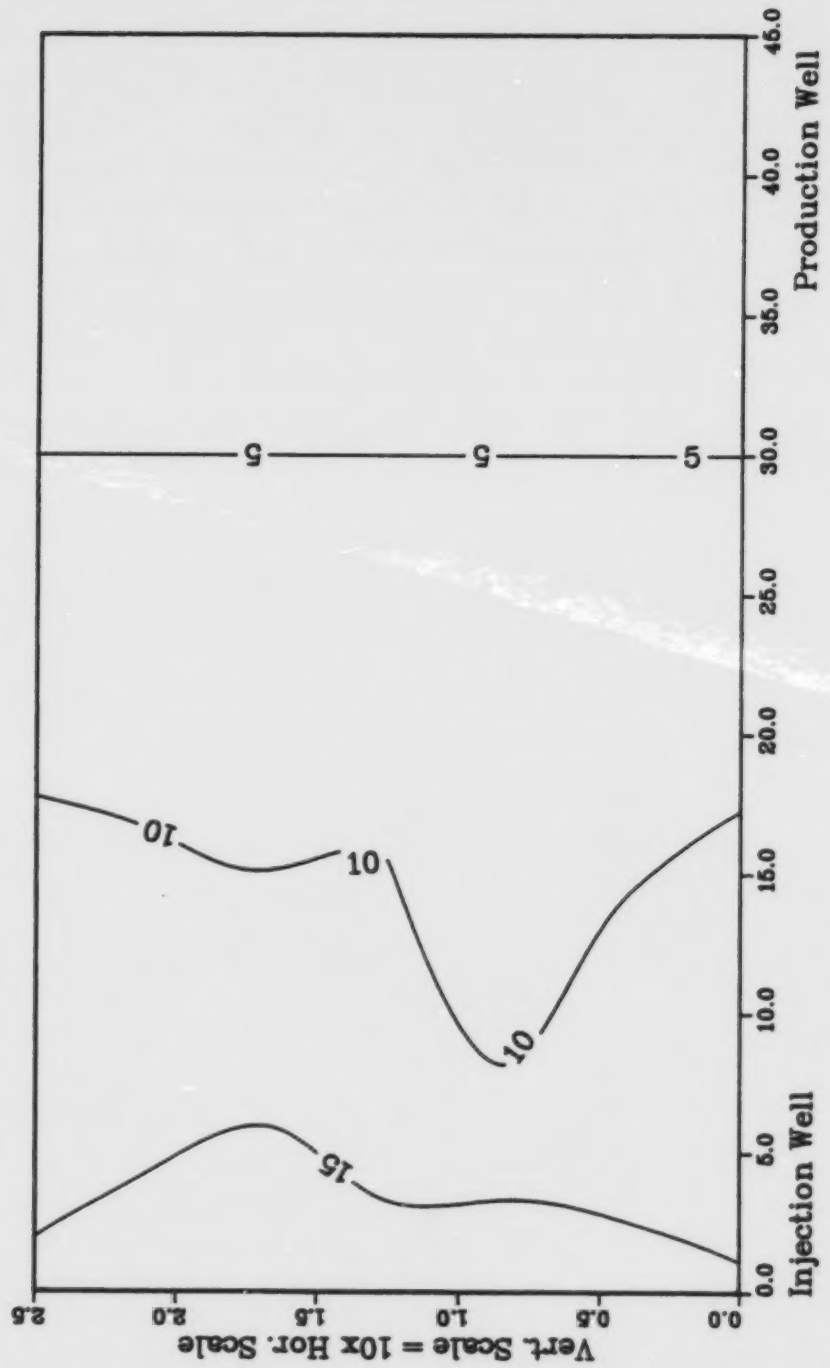


**Figure A.21 :Run 40 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

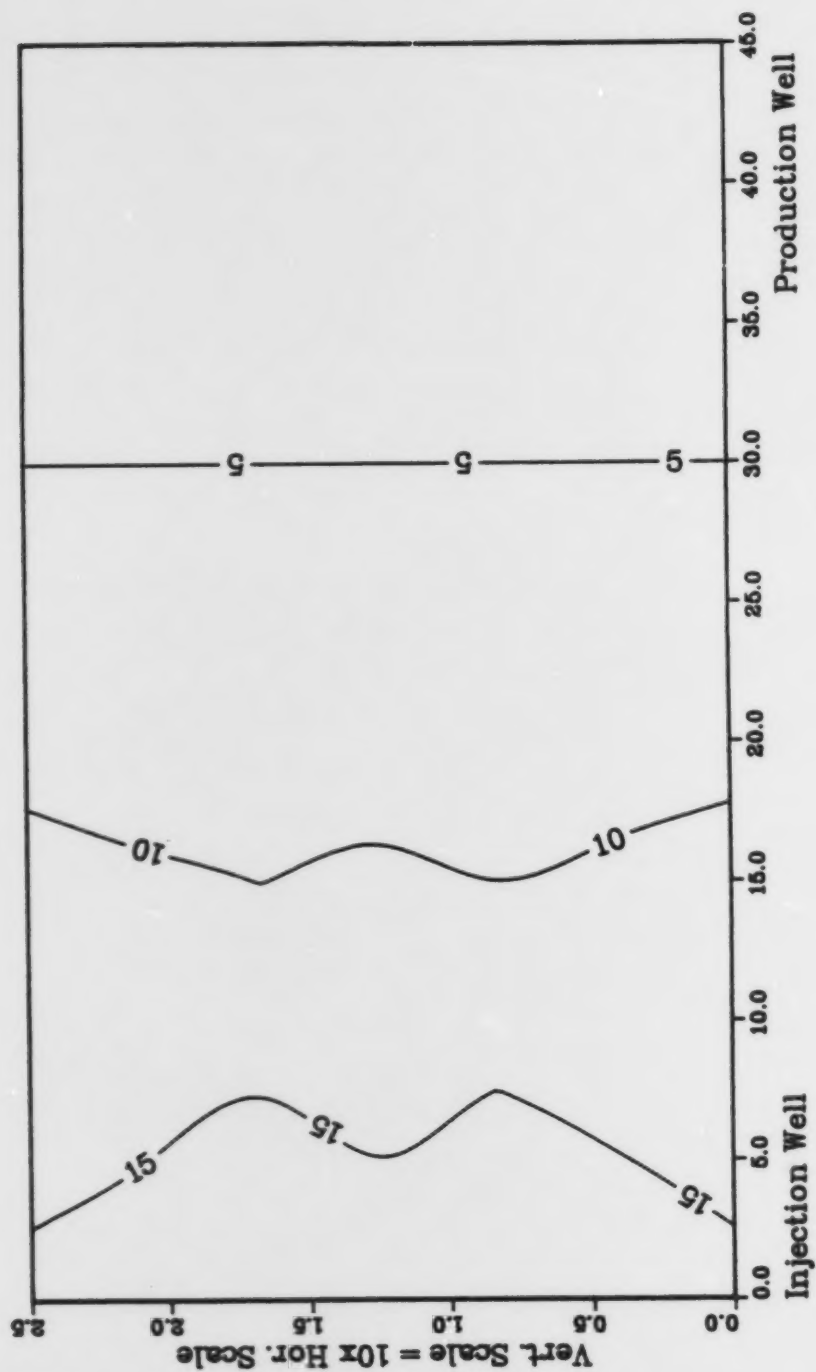


**Figure A.22 :Run 40 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

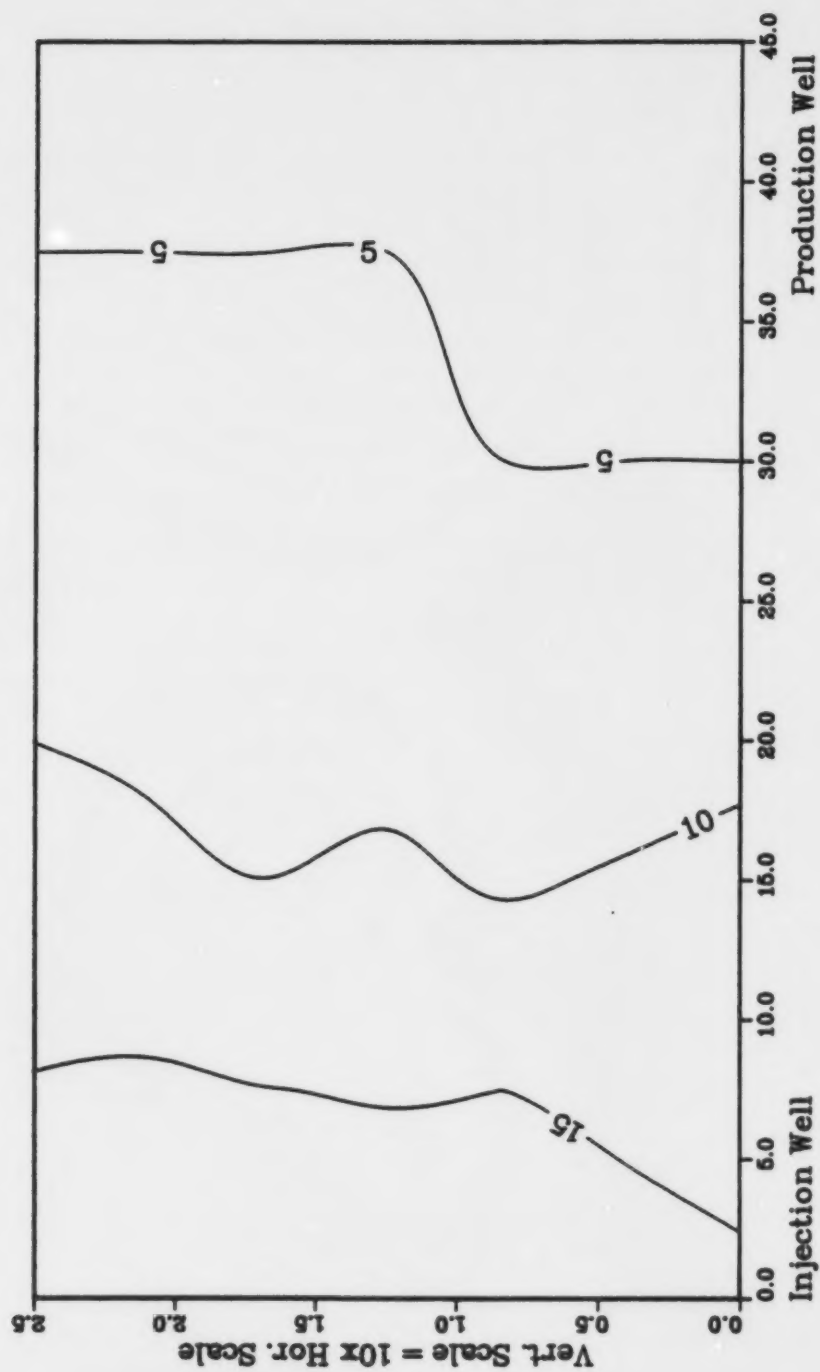


Figure A.23 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.25 Pore Volumes Injected

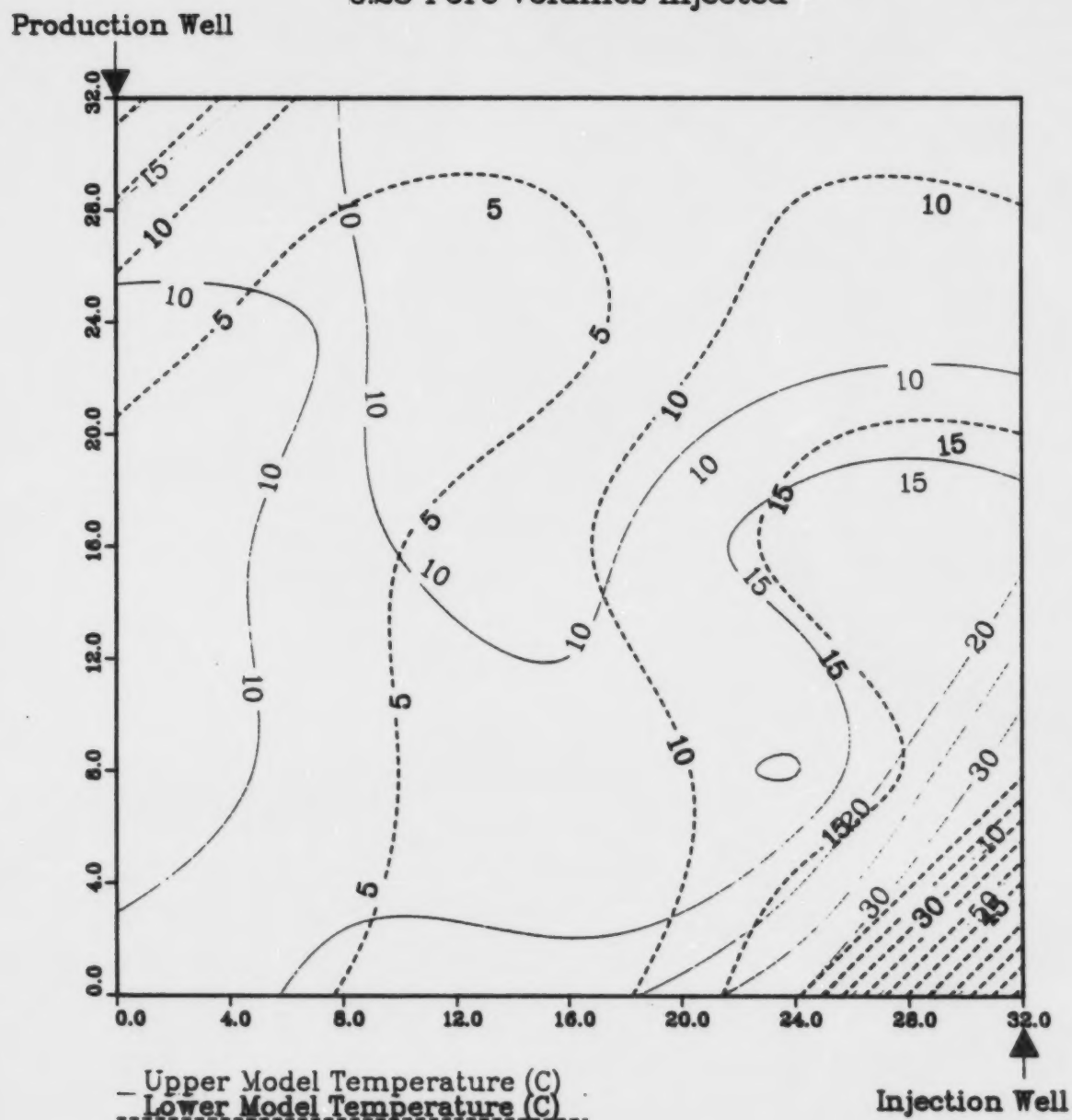


Figure A.24 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.50 Pore Volumes Injected

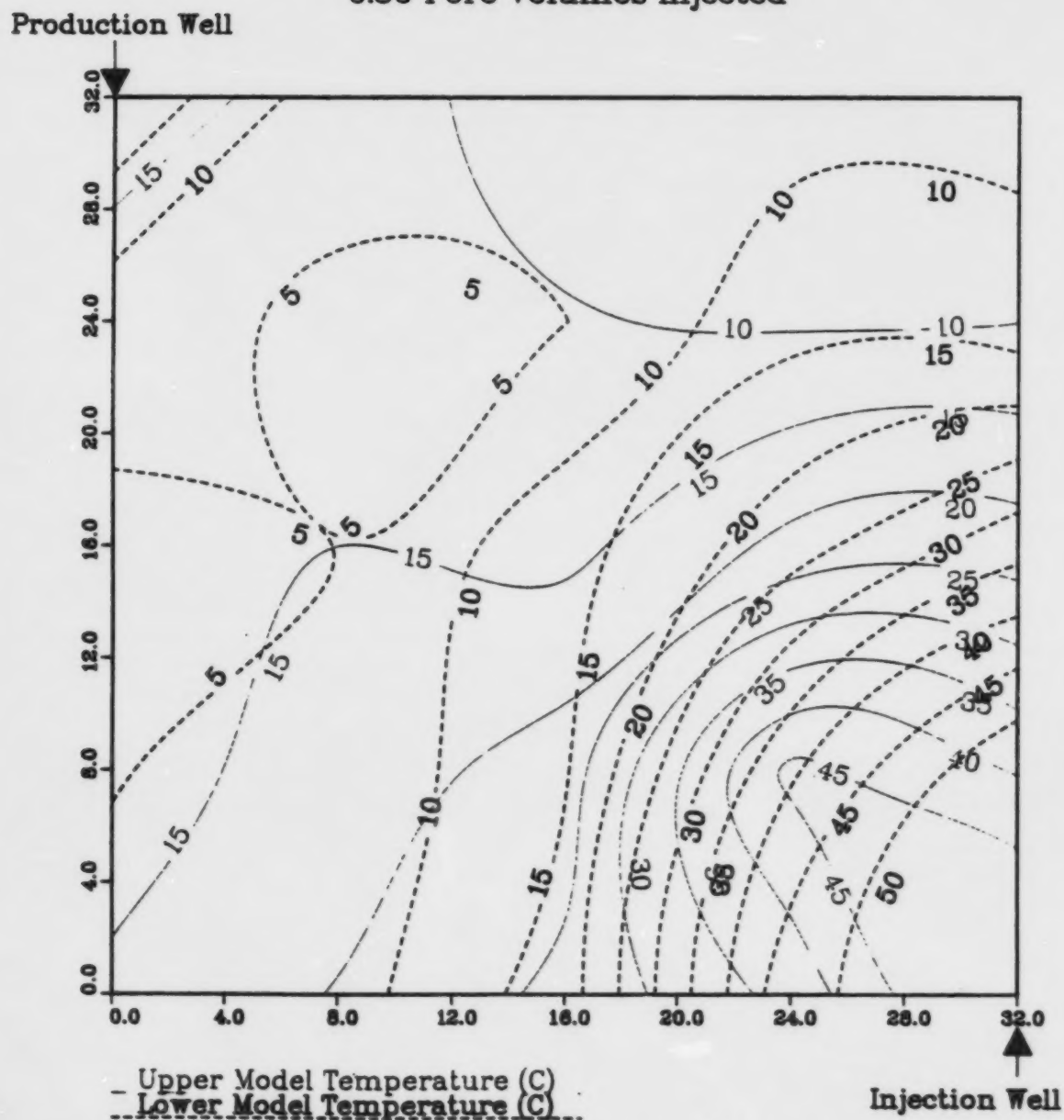


Figure A.25 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.75 Pore Volumes Injected

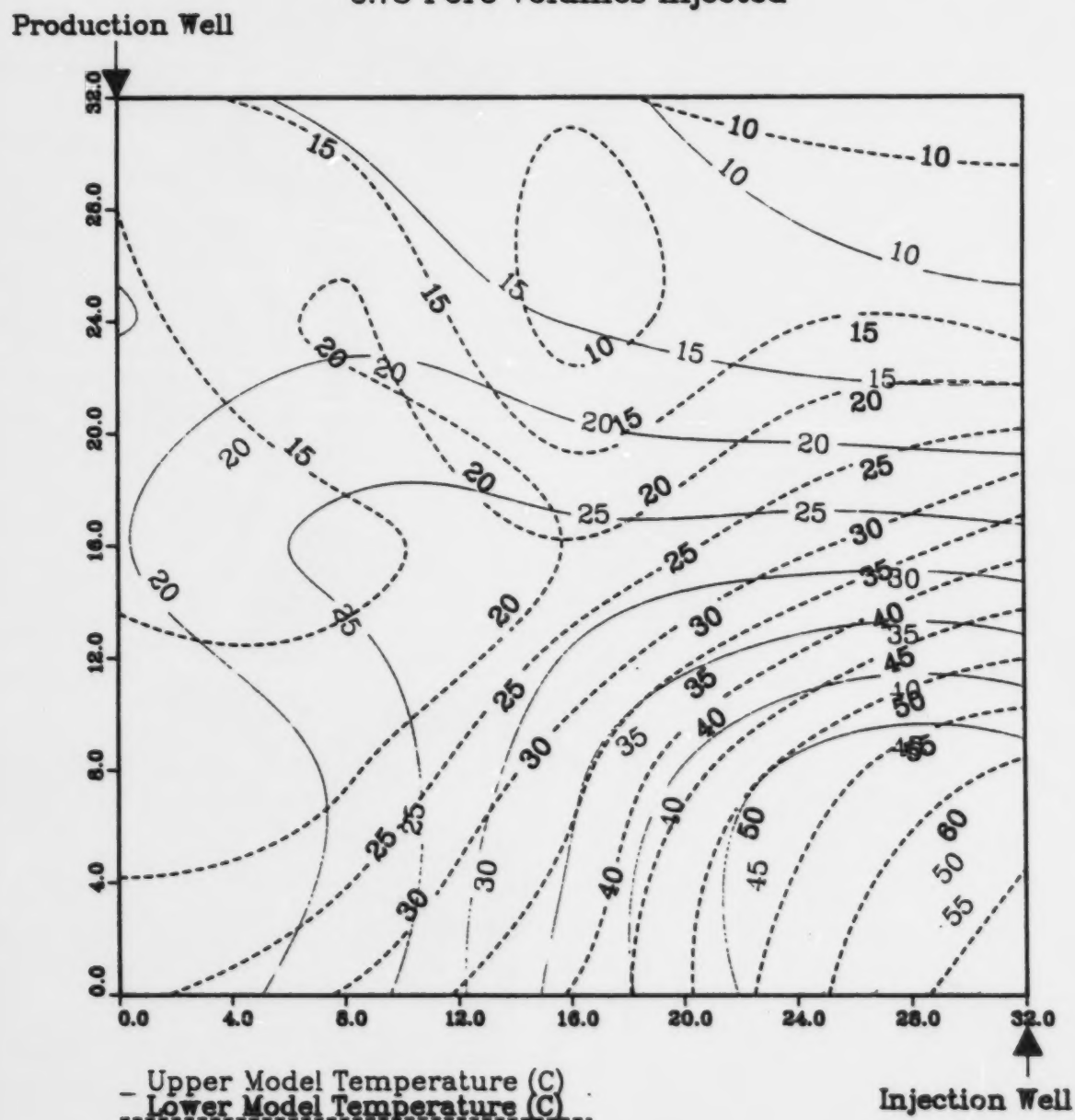


Figure A.26 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.00 Pore Volumes Injected

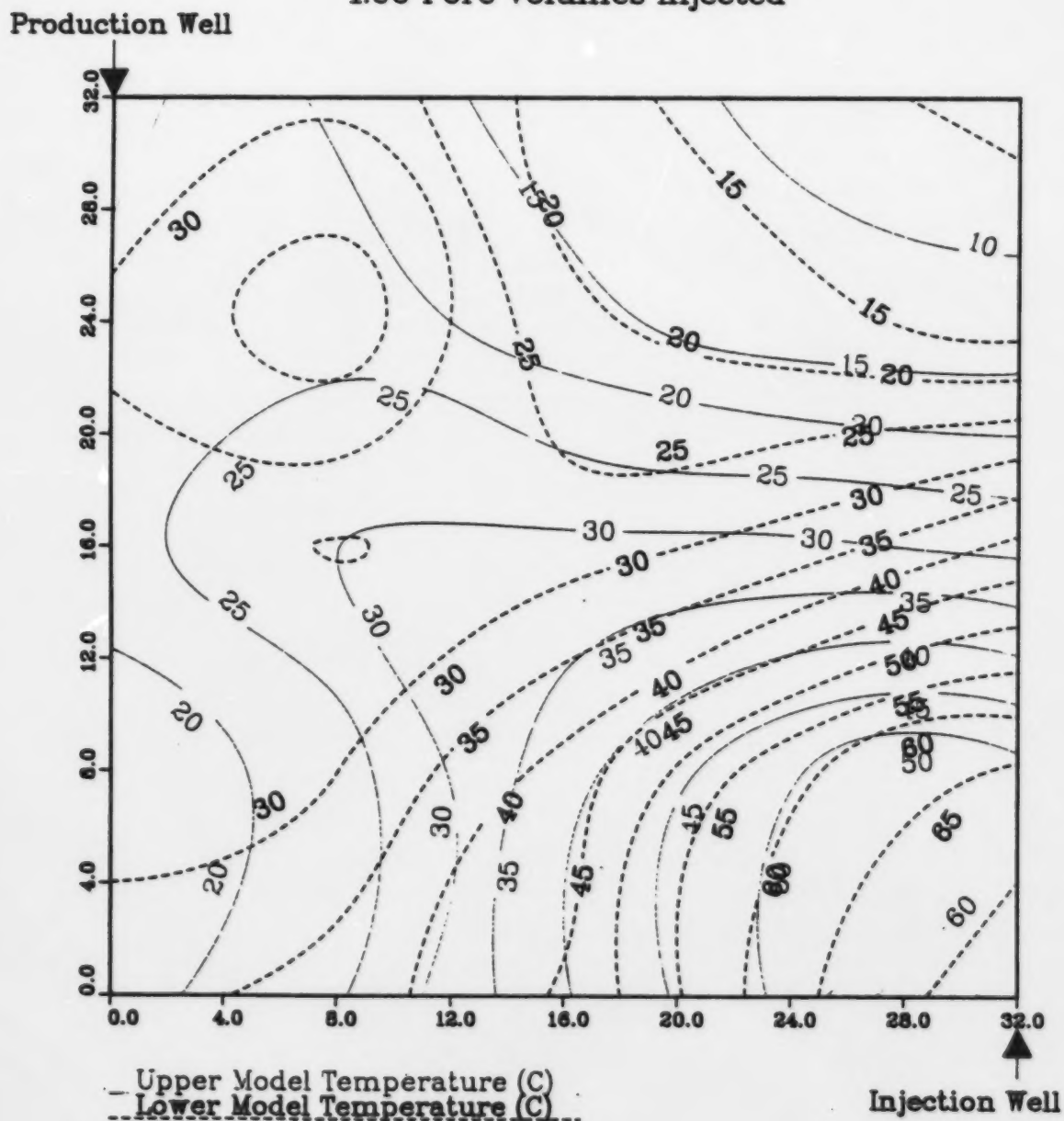
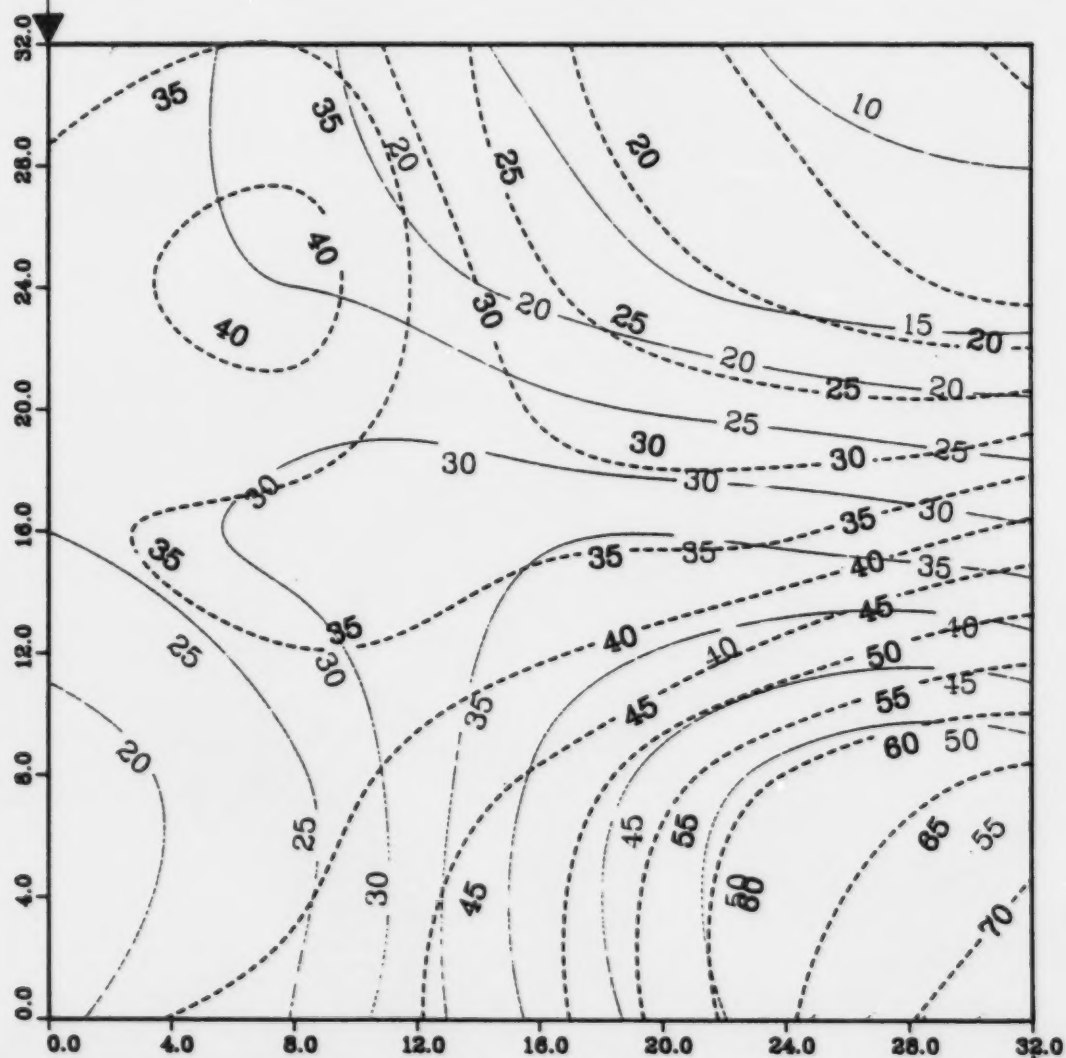


Figure A.27 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



— Upper Model Temperature (C)

- - - Lower Model Temperature (C)

Injection Well

Figure A.28 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.50 Pore Volumes Injected

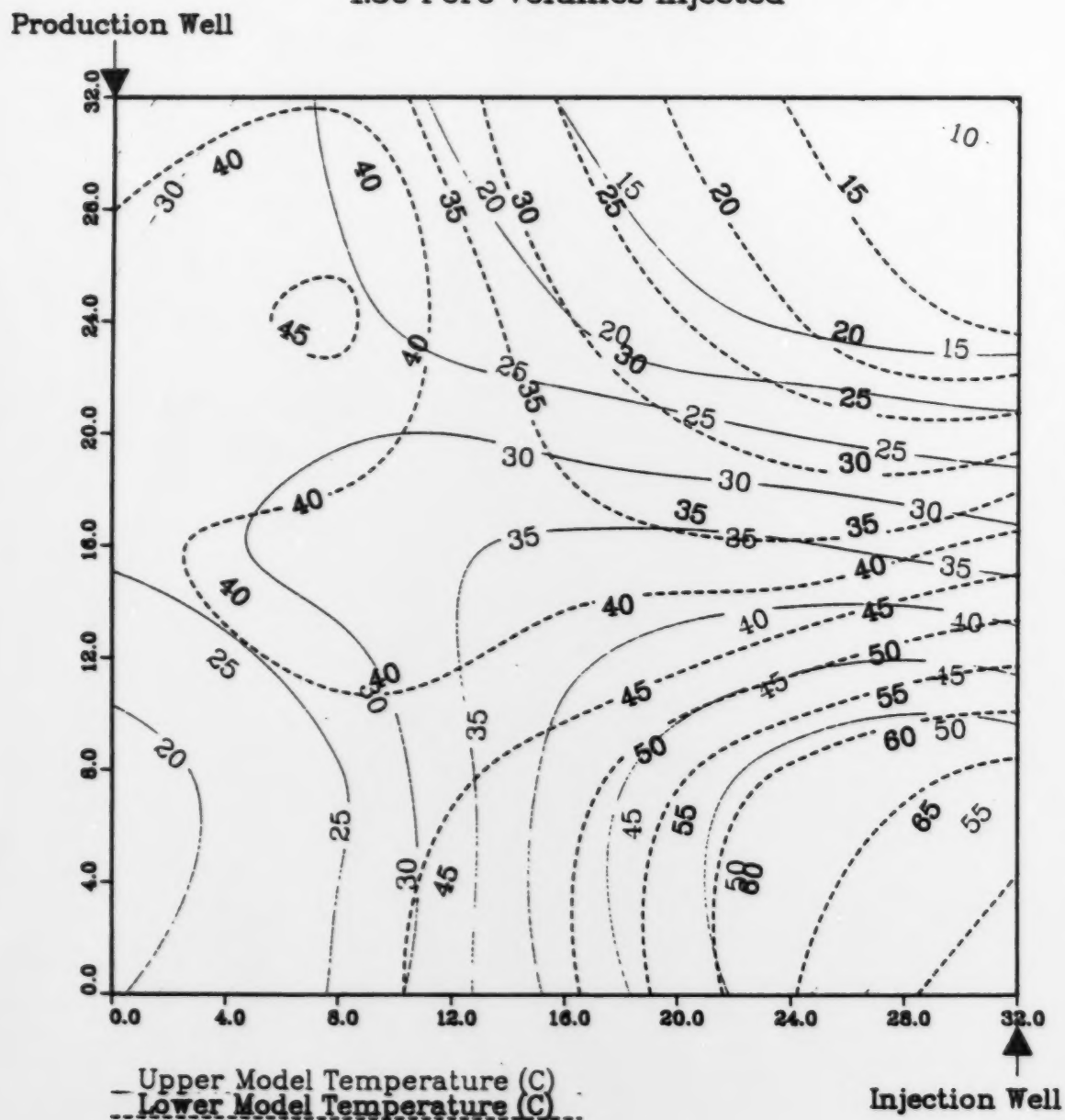
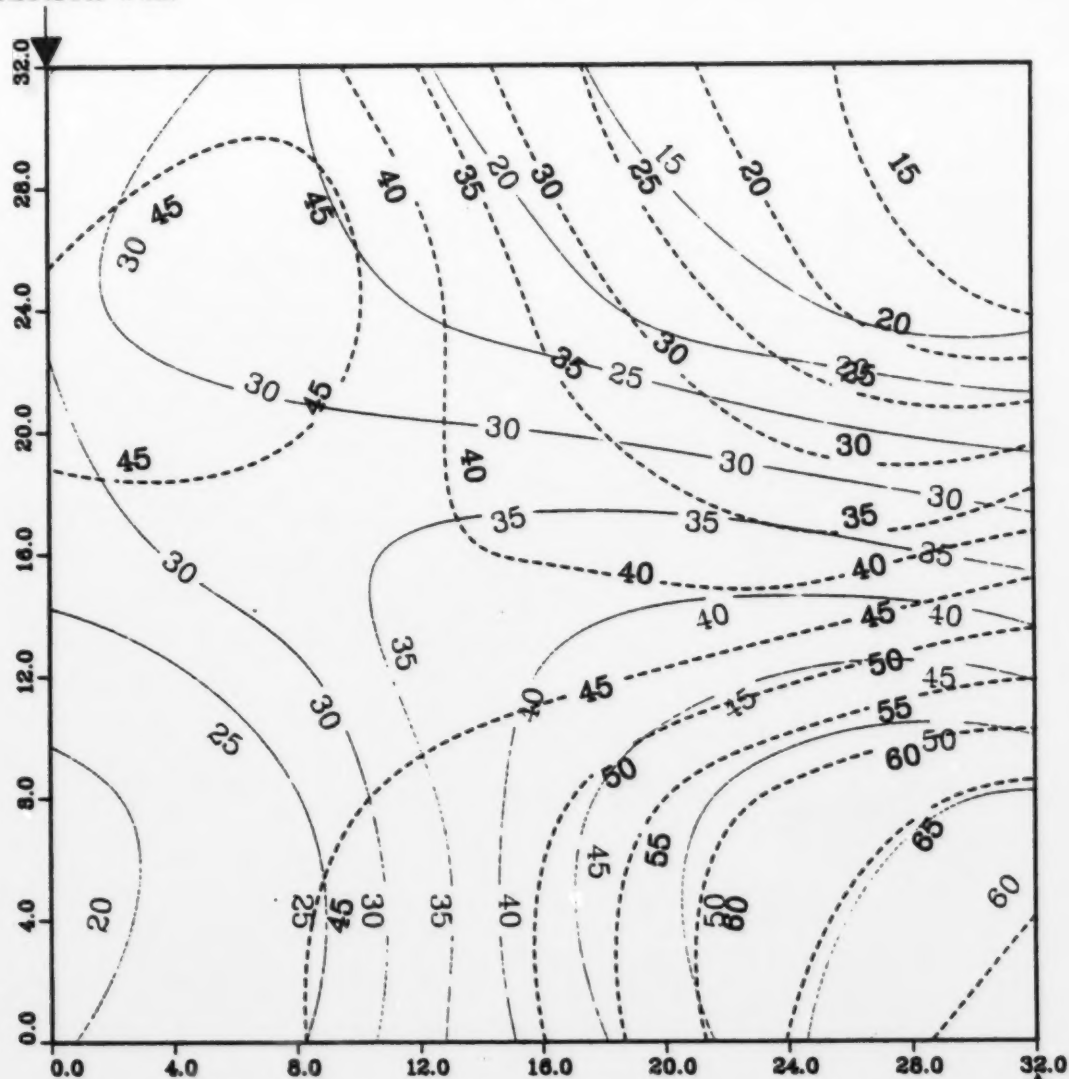


Figure A.29 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



— Upper Model Temperature (C)
- - Lower Model Temperature (C)

Injection Well

Figure A.30 : Run 44
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
2.00 Pore Volumes Injected

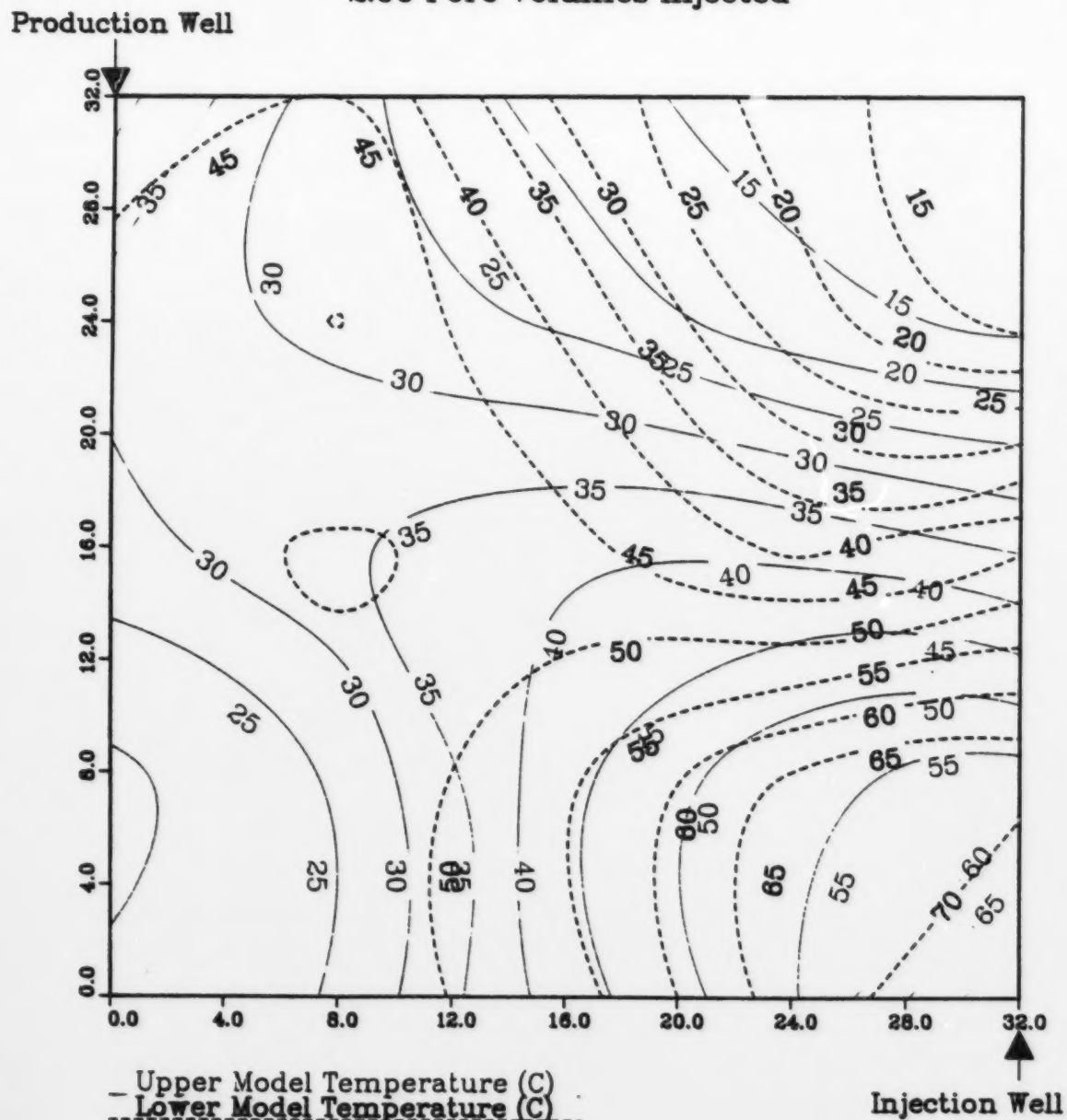


**Figure A.31 :Run 44 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

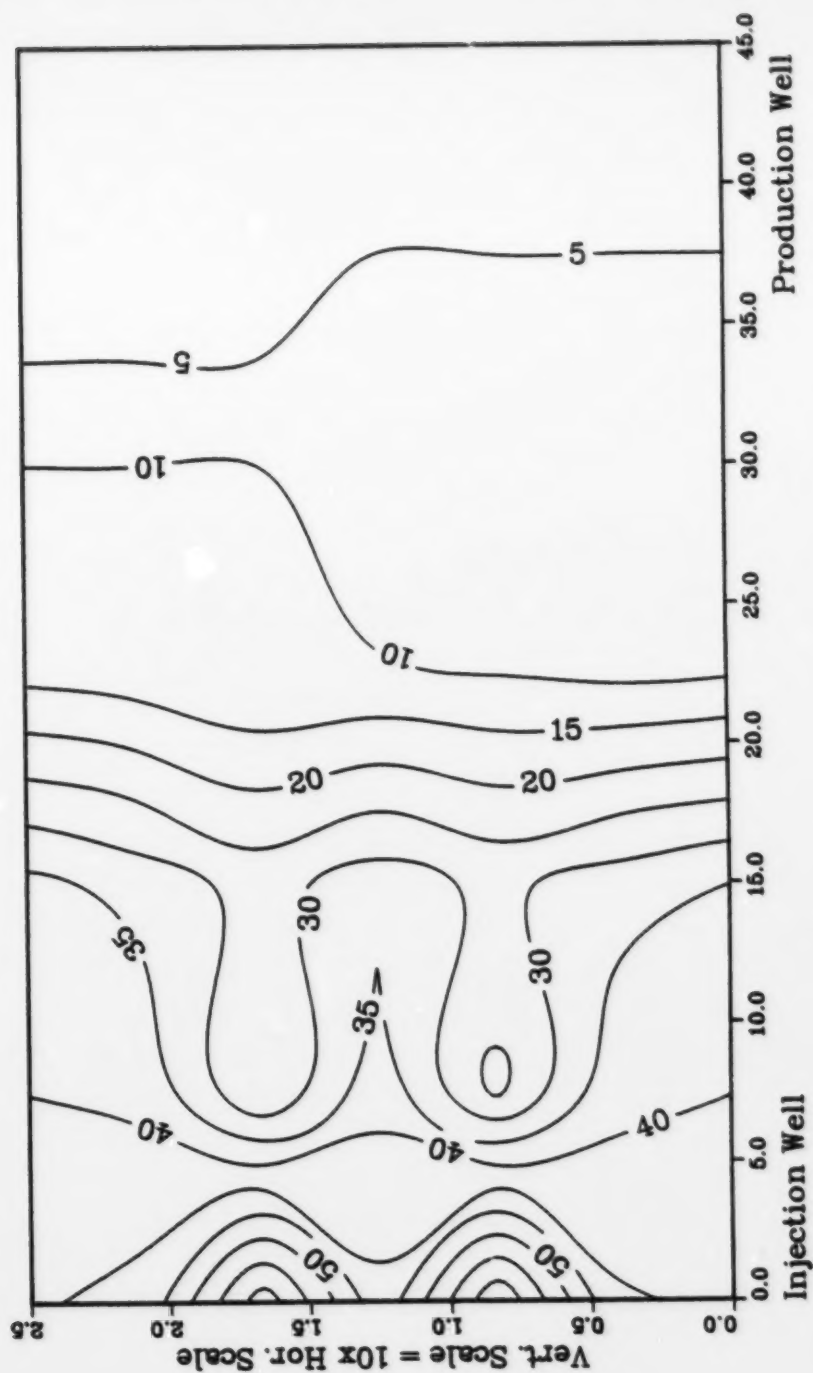


Figure A.32 :Run 44 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.

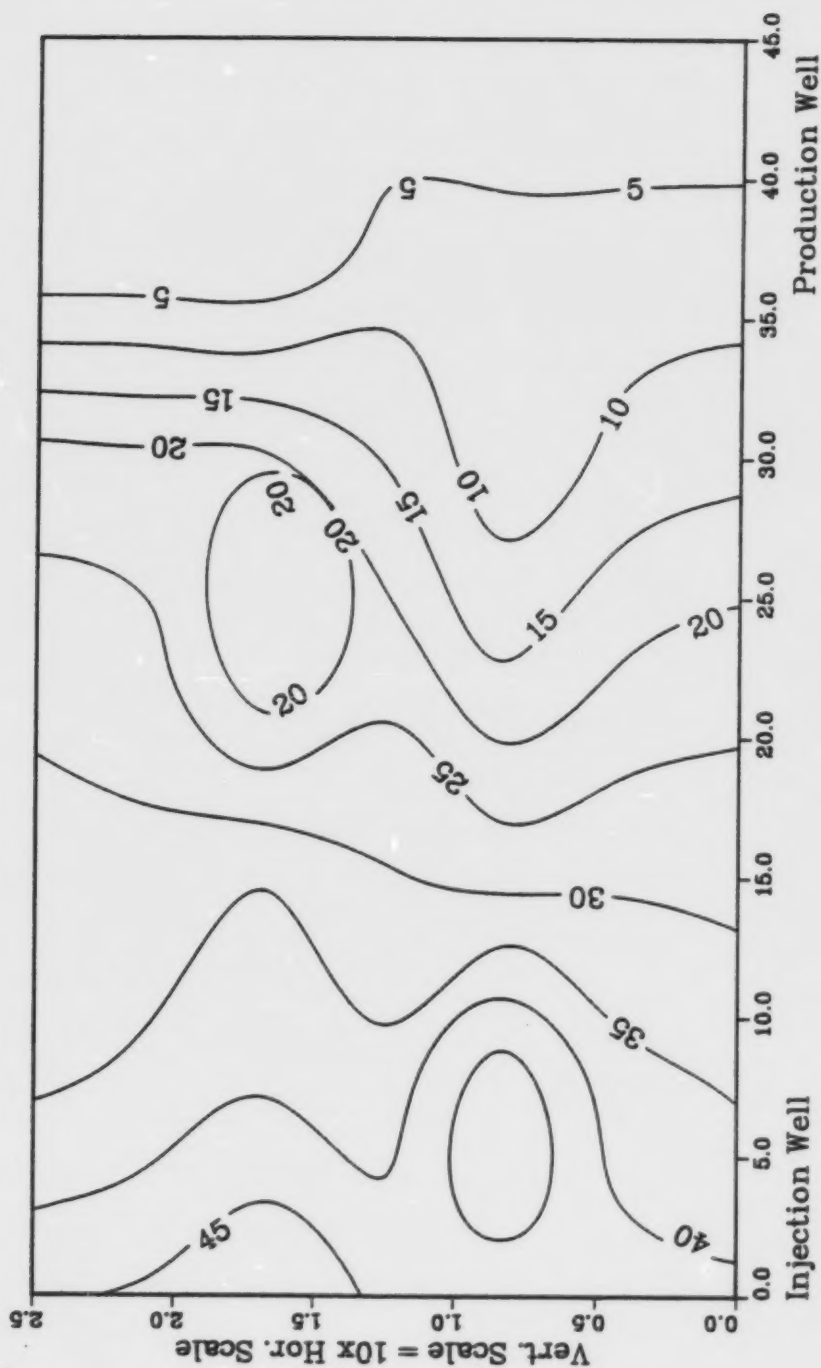


Figure A.33 :Run 44 Temp Profile
 Injector to Producer Cross-Section
 0.75 Pore Volumes Injected.

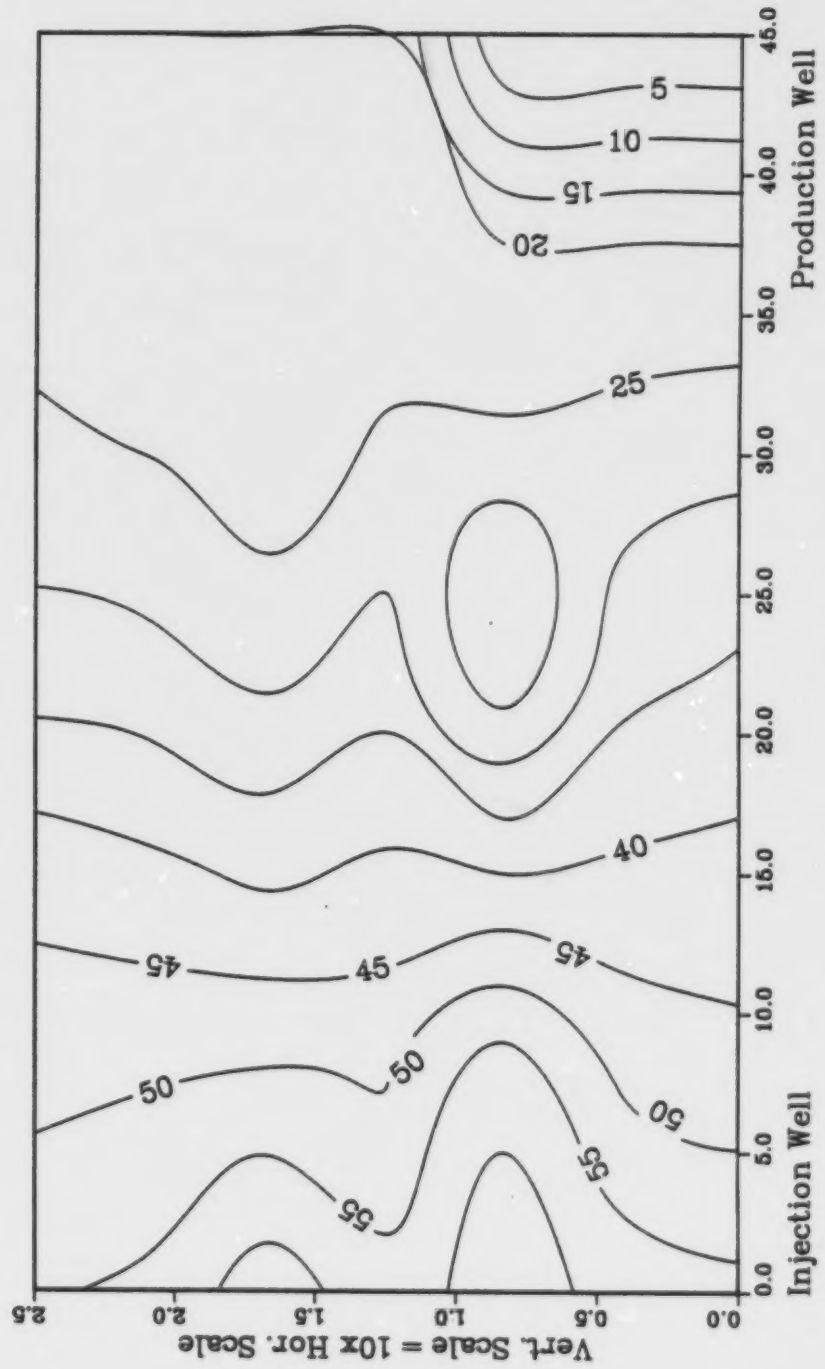


**Figure A.34 :Run 44 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

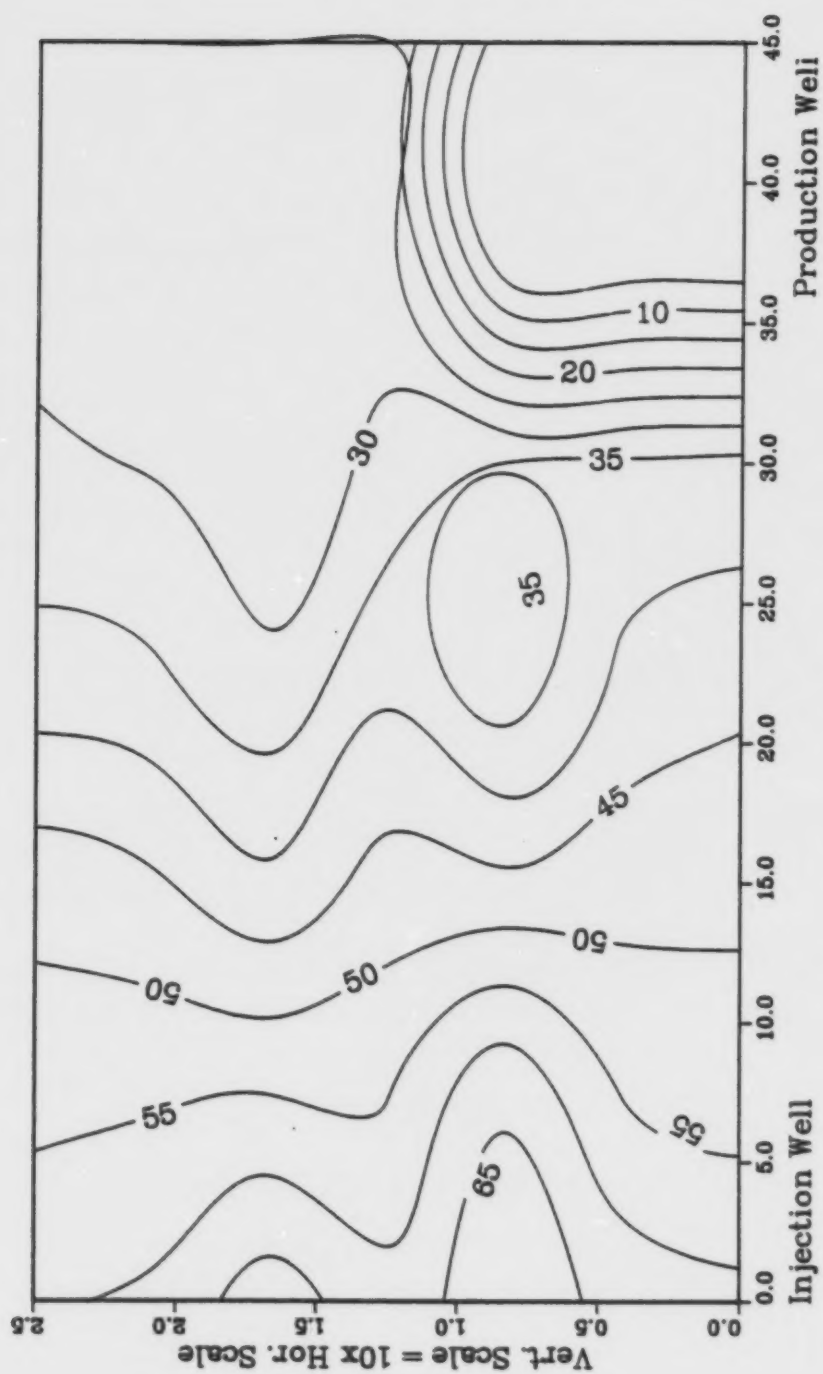


Figure A.35 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.25 Pore Volumes Injected

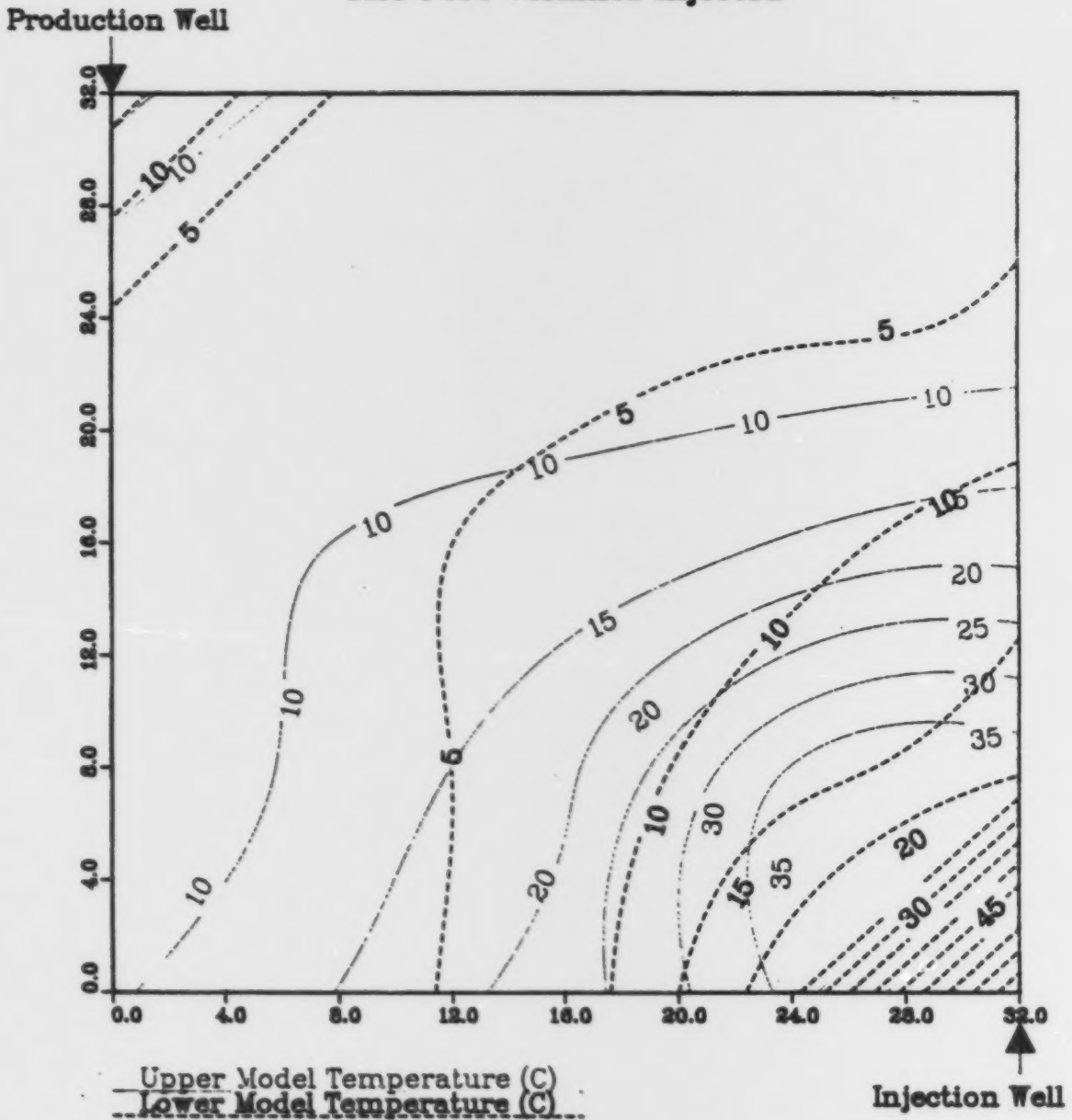


Figure A.36 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.50 Pore Volumes Injected

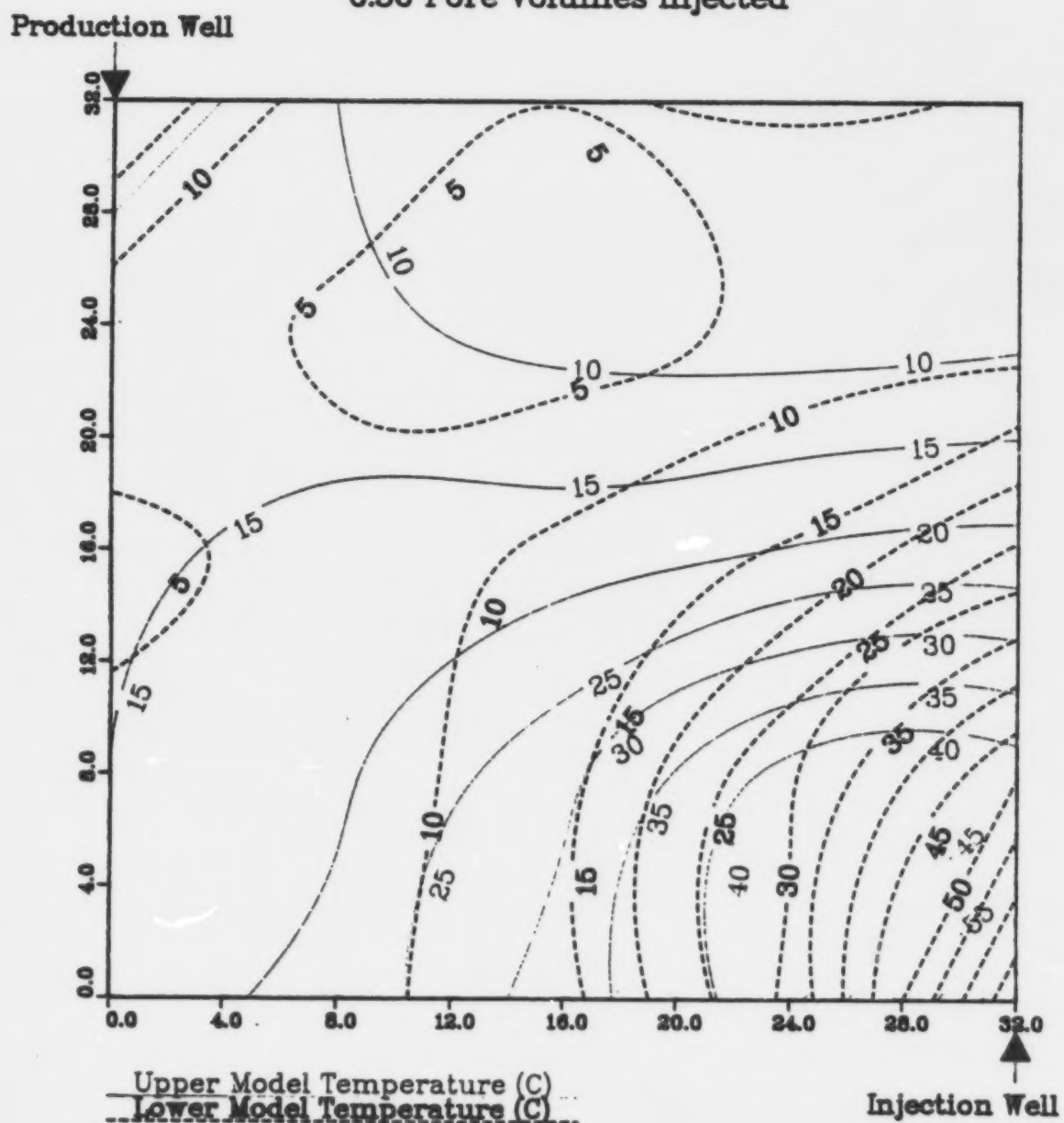
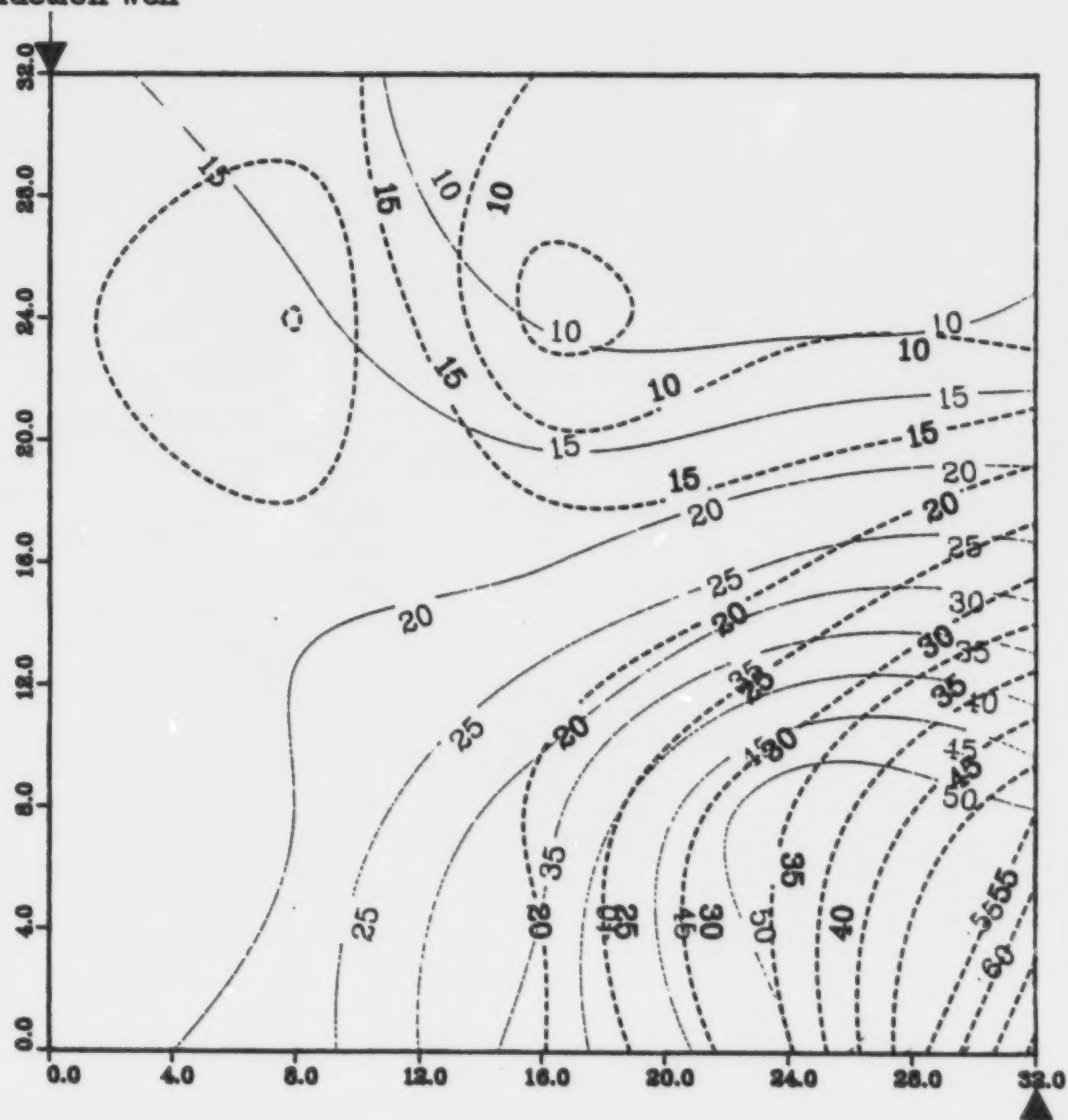


Figure A.37 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

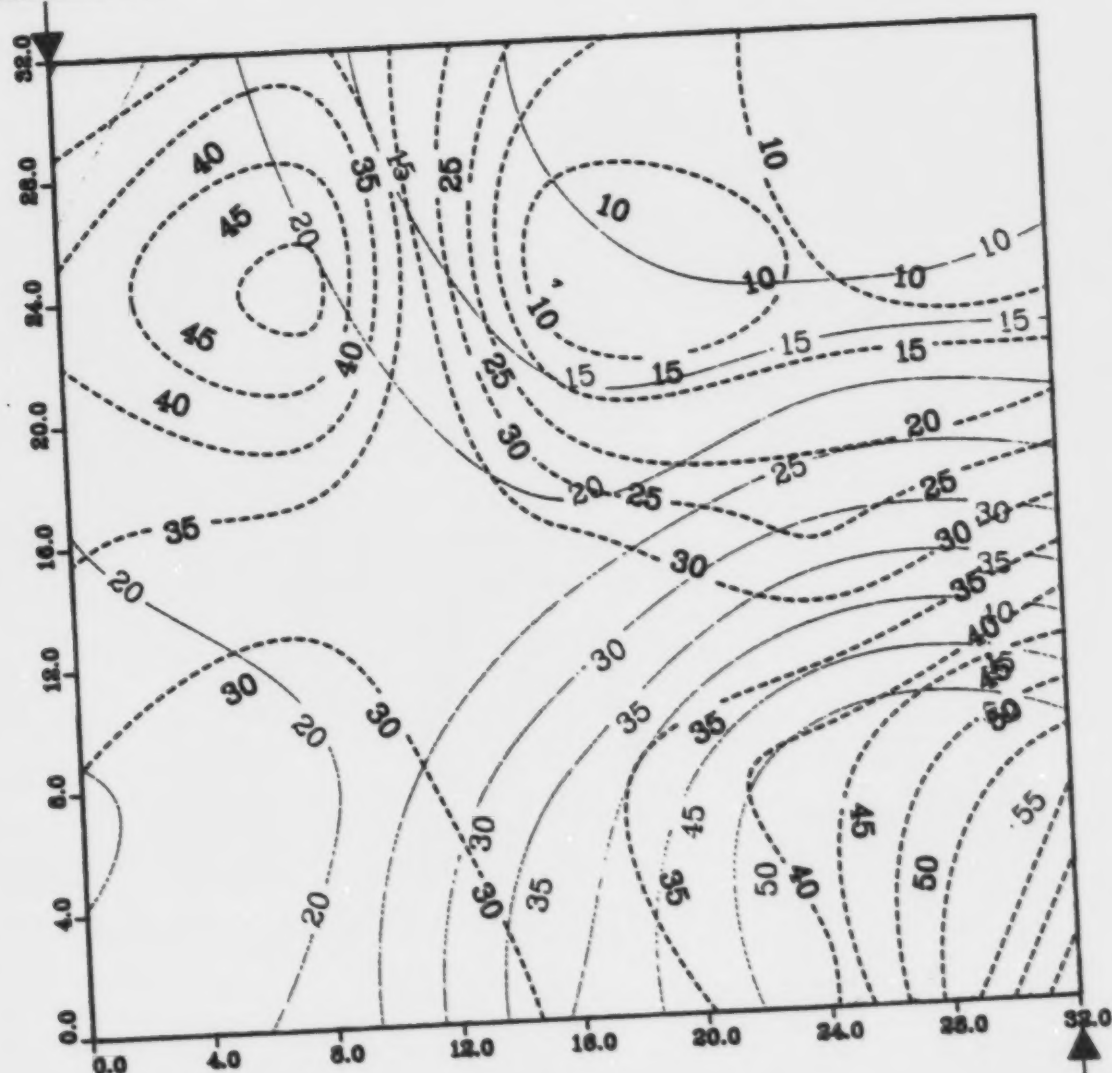
Lower Model Temperature (C)

Injection Well

Figure A.38 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



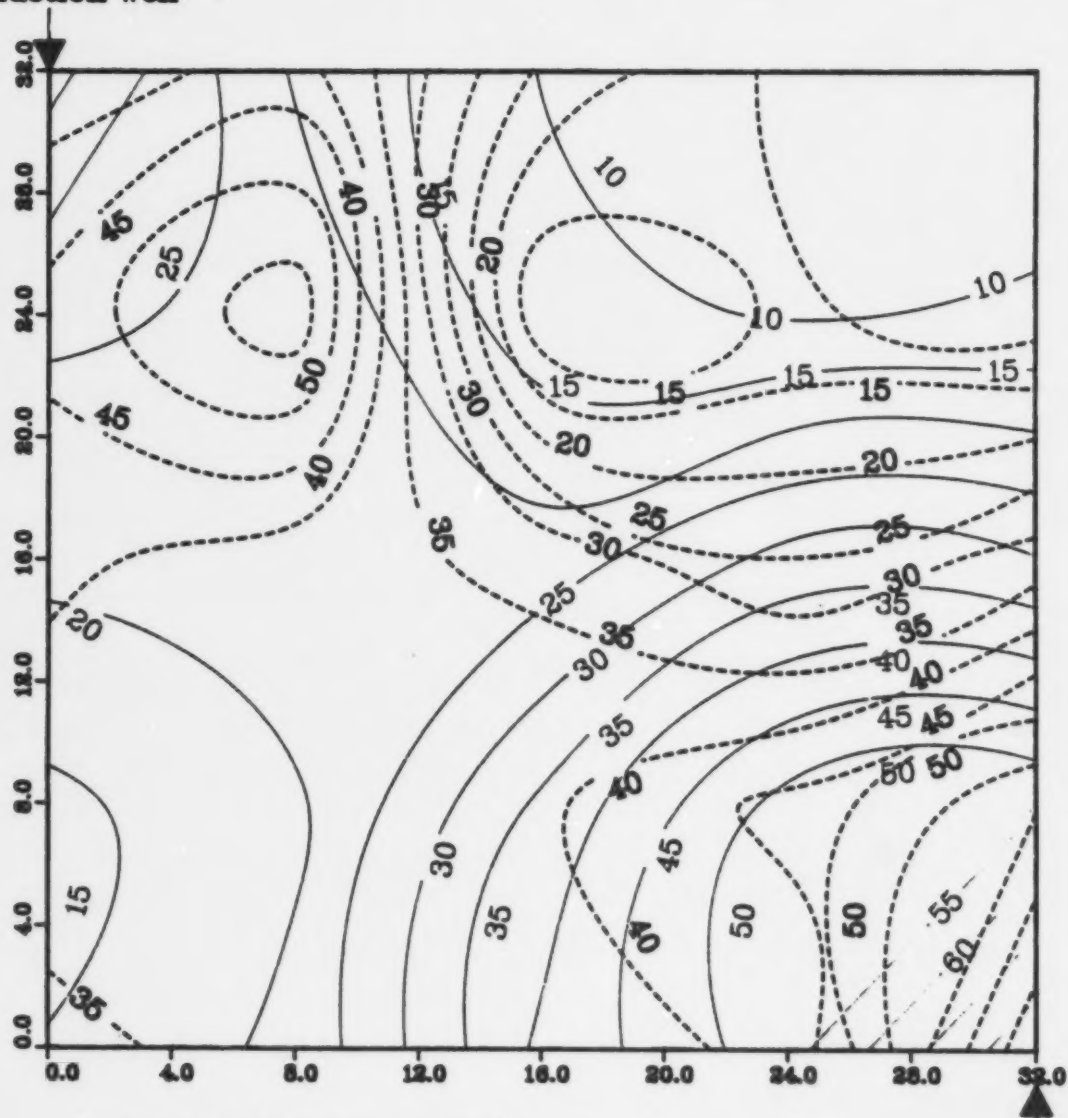
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.39 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



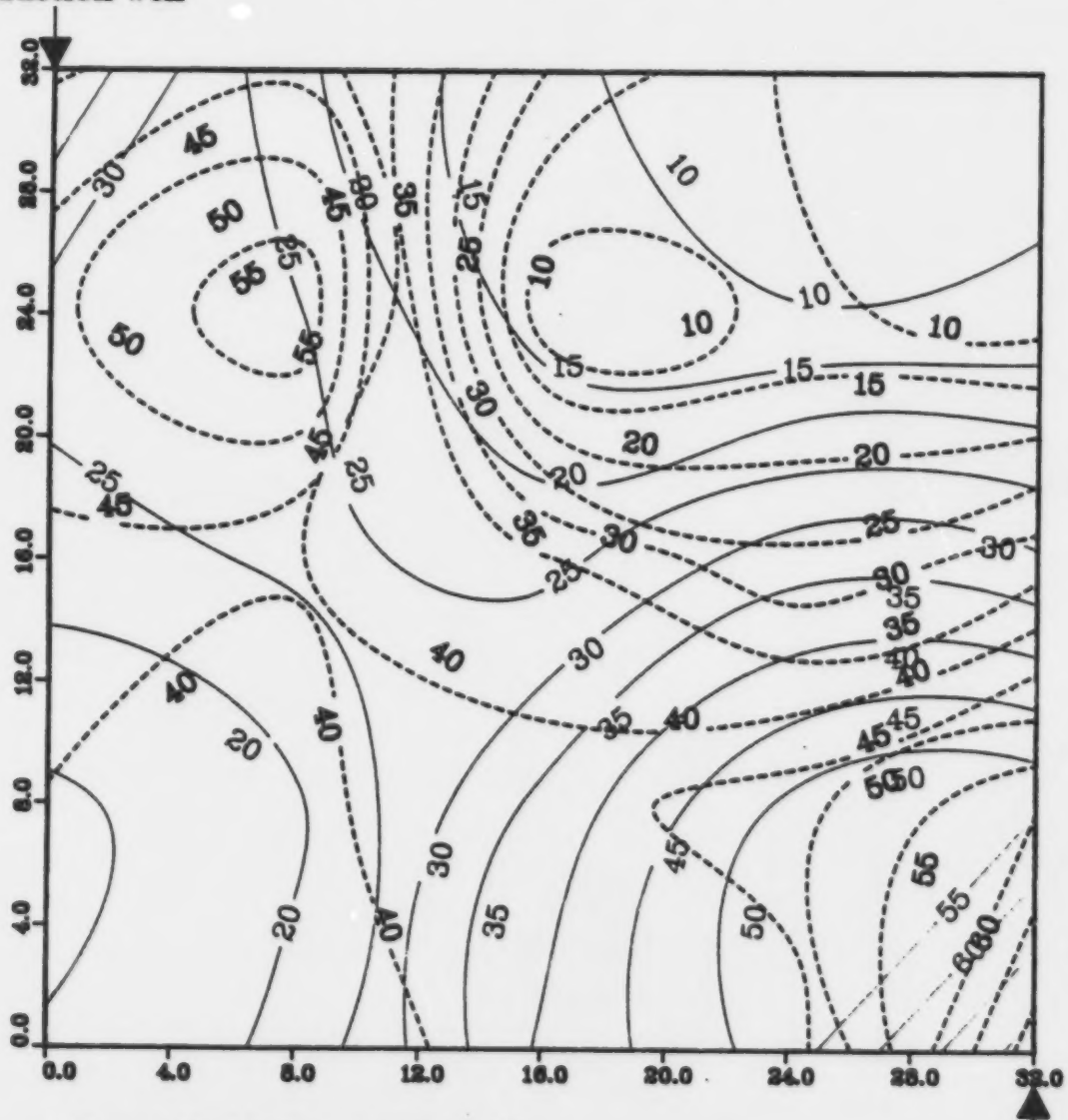
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.40 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



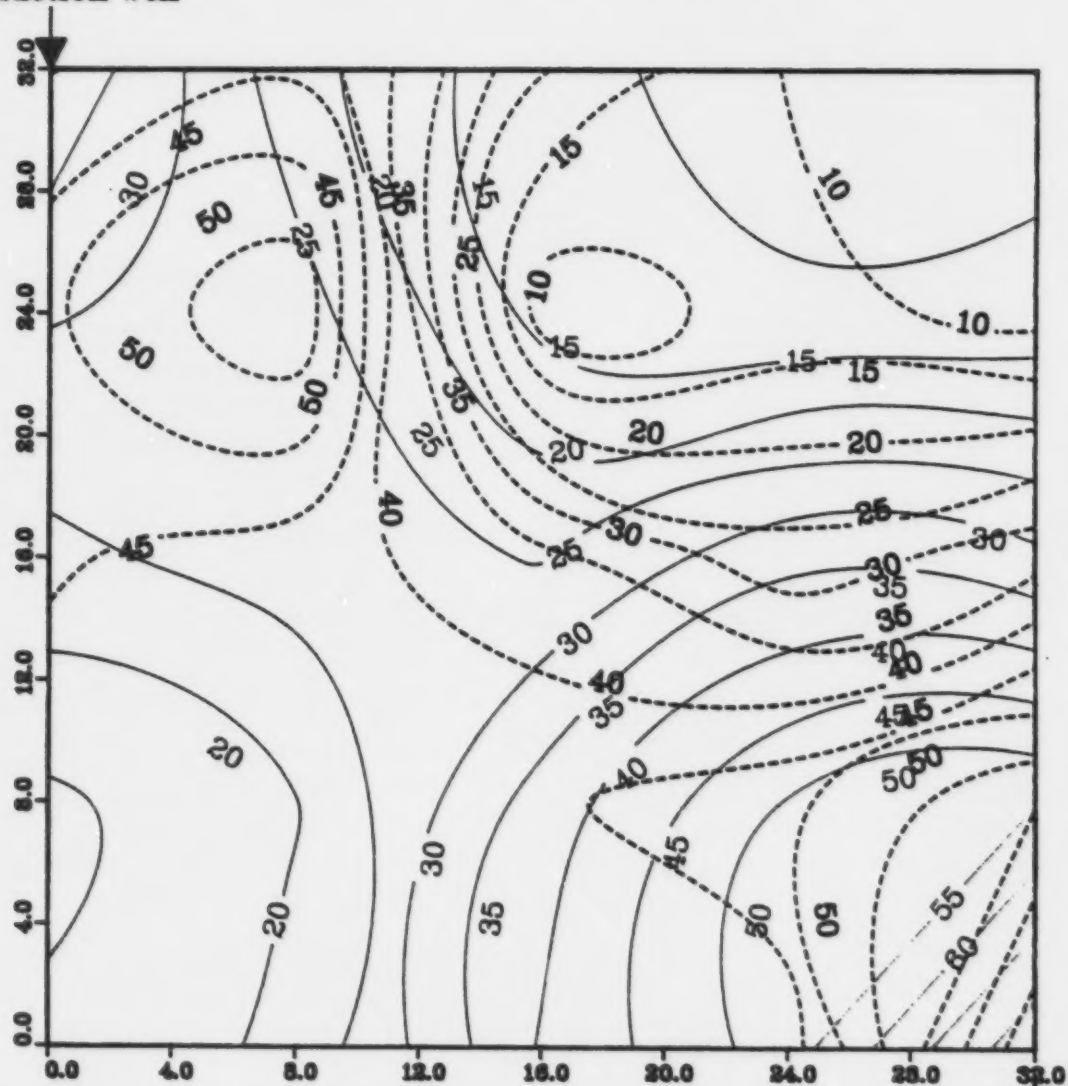
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.41 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.42 : Run 45
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
2.00 Pore Volumes Injected

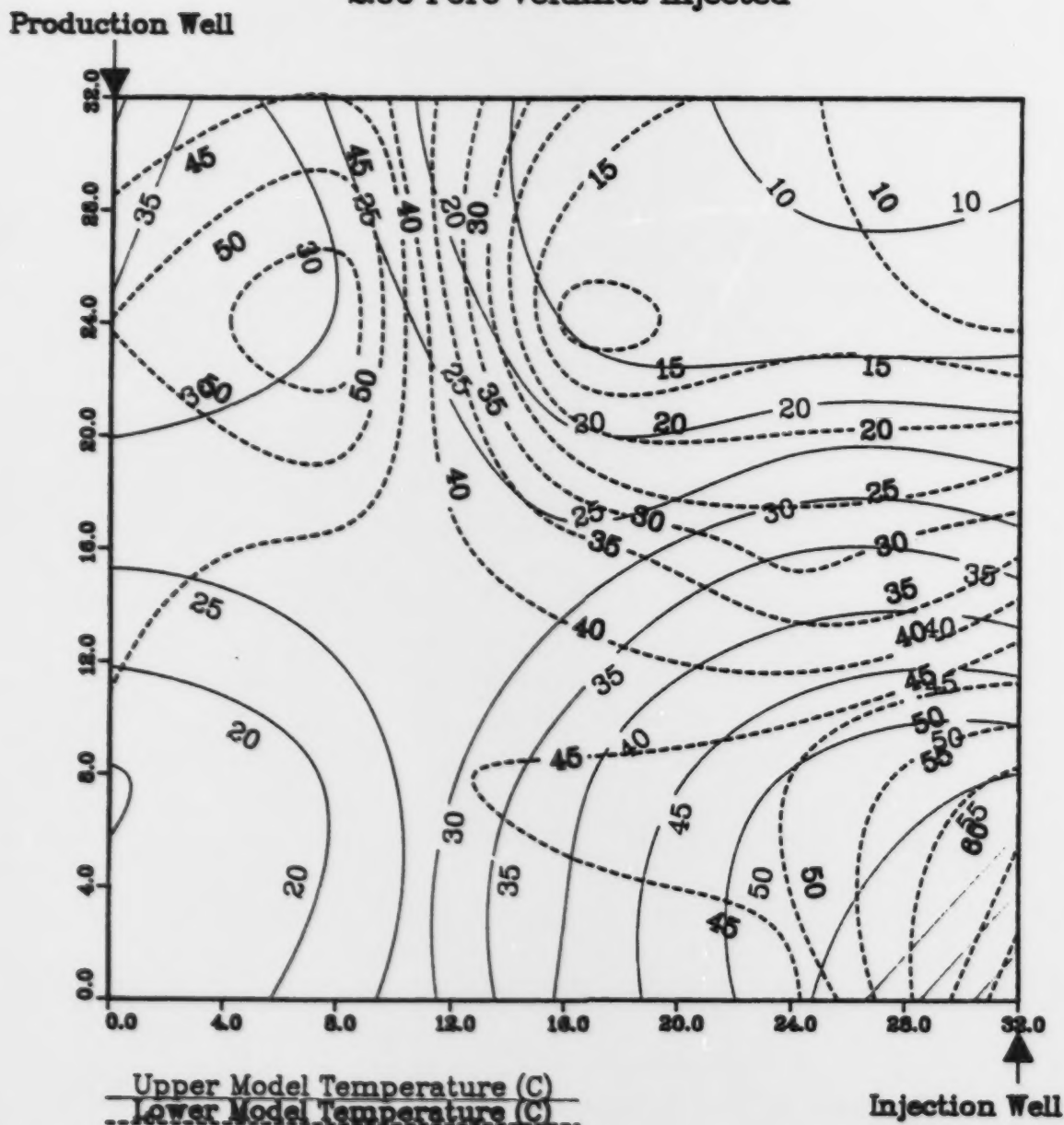


**Figure A.43 :Run 45 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

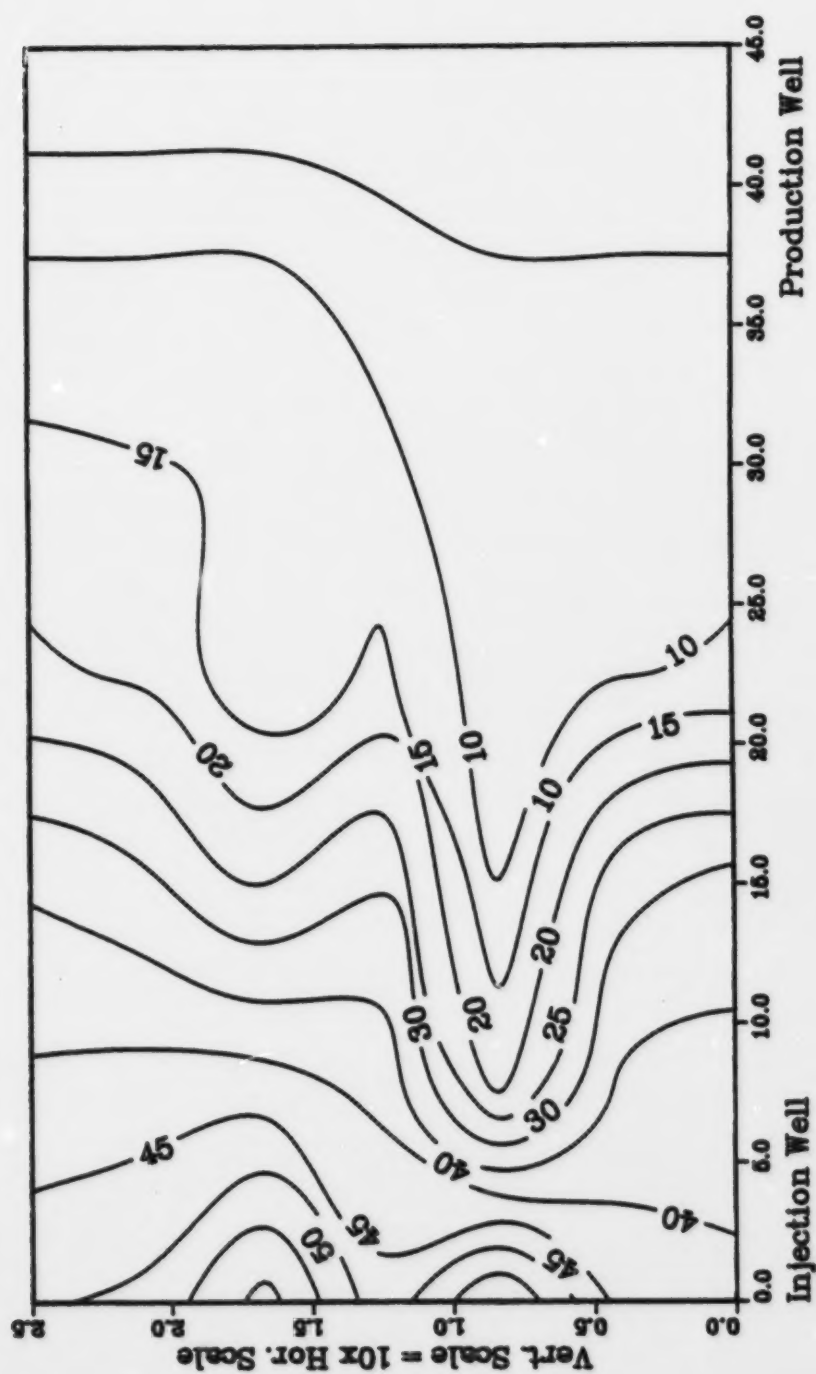


**Figure A.44 :Run 45 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

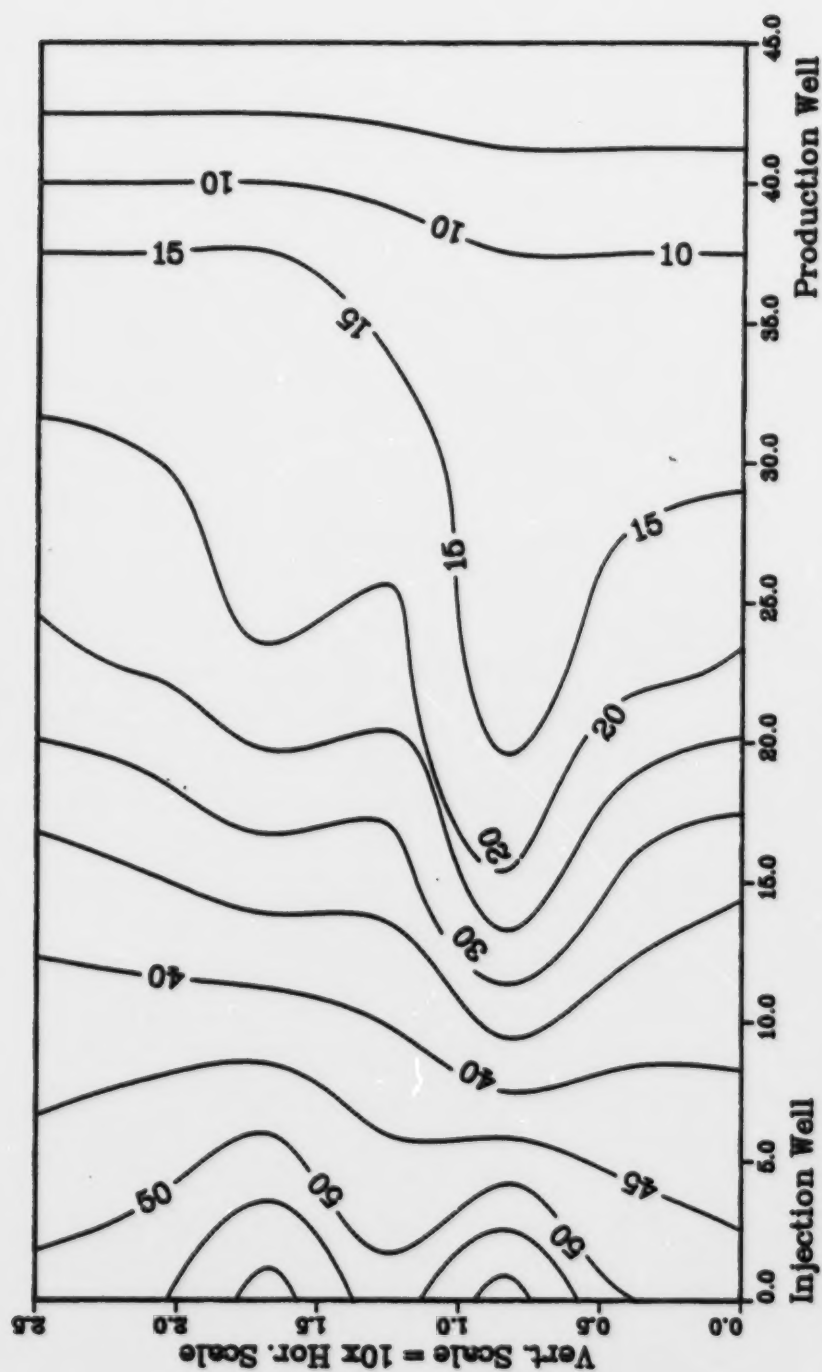


**Figure A.45 :Run 45 Temp Profile
Injector to Producer Cross-Section**
0.76 Pore Volumes Injected.

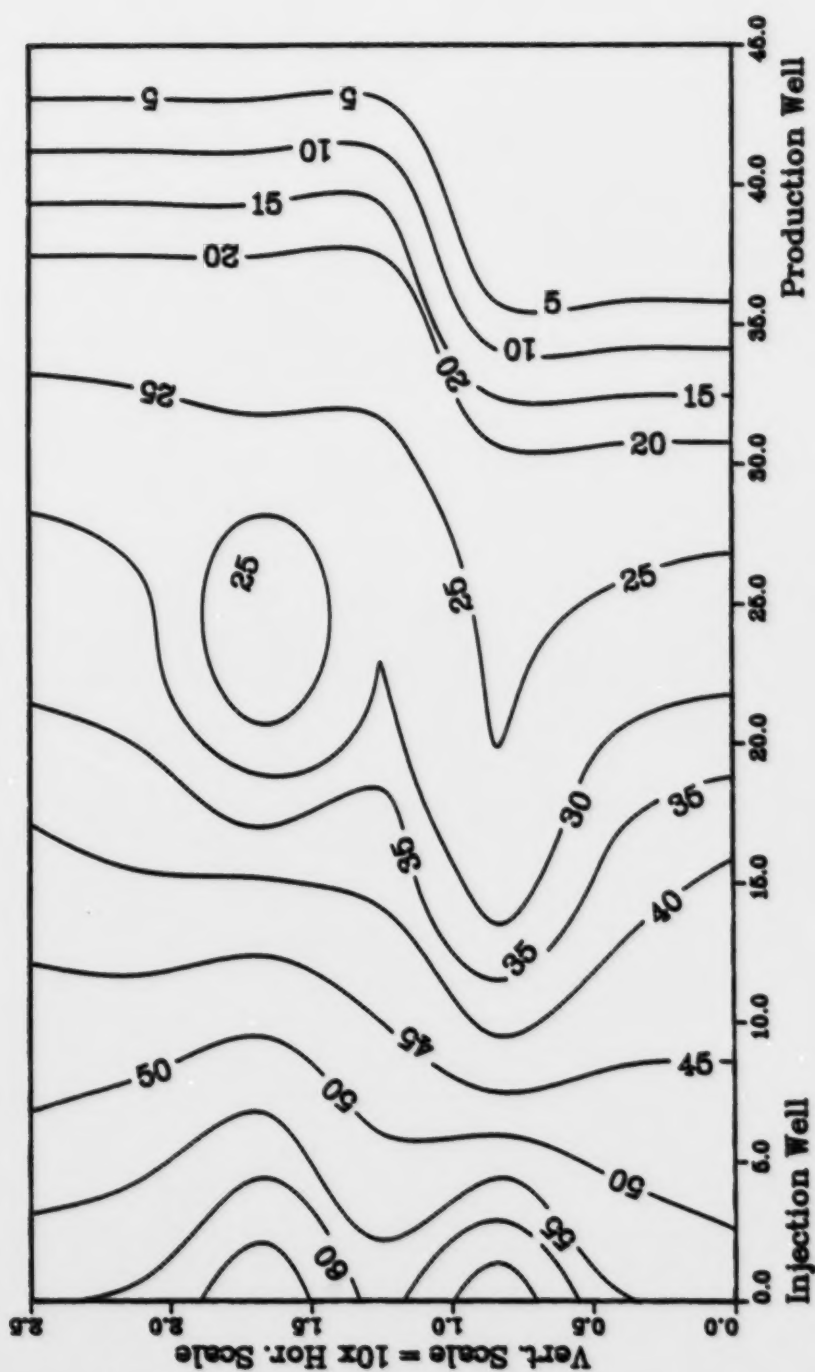


**Figure A.46 :Run 45 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

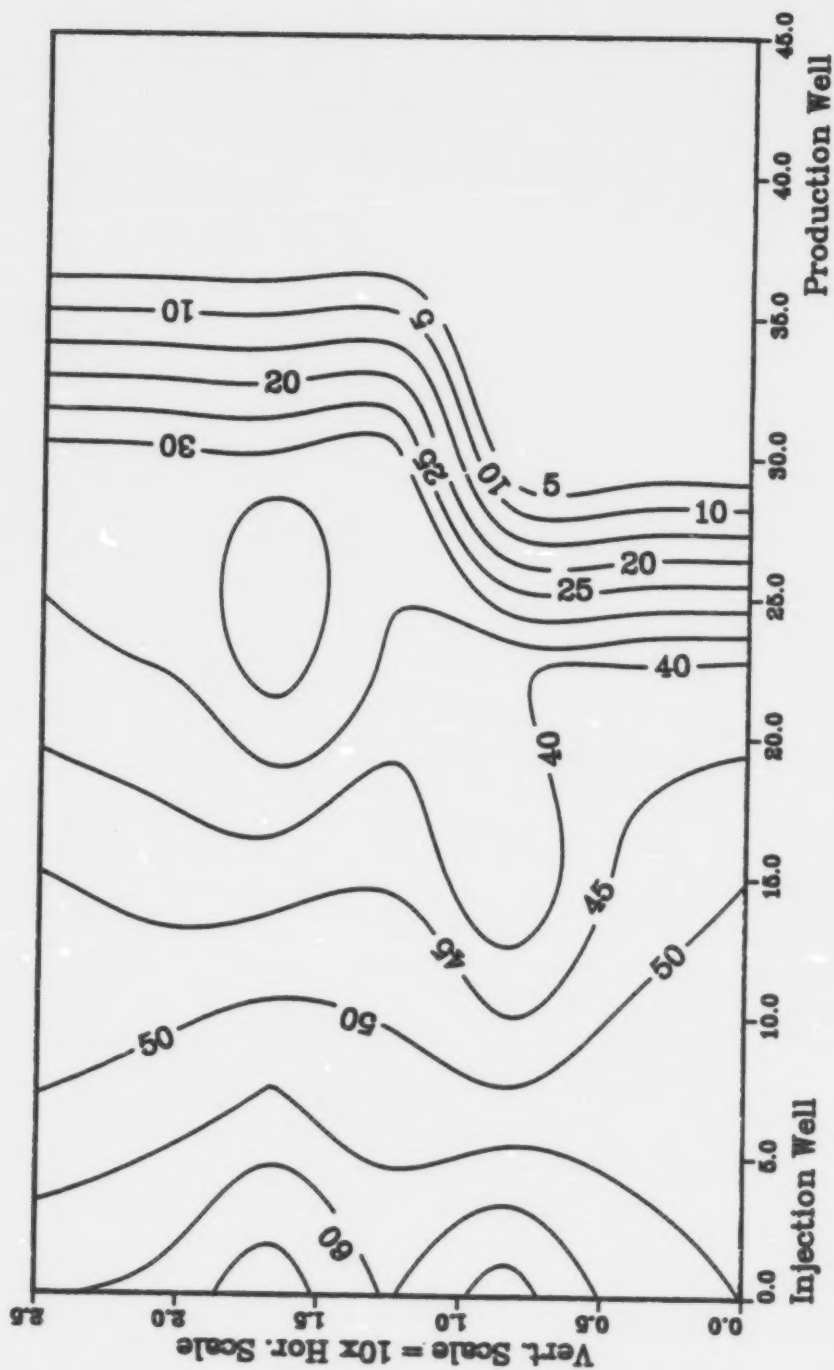


Figure A.47 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.25 Pore Volumes Injected

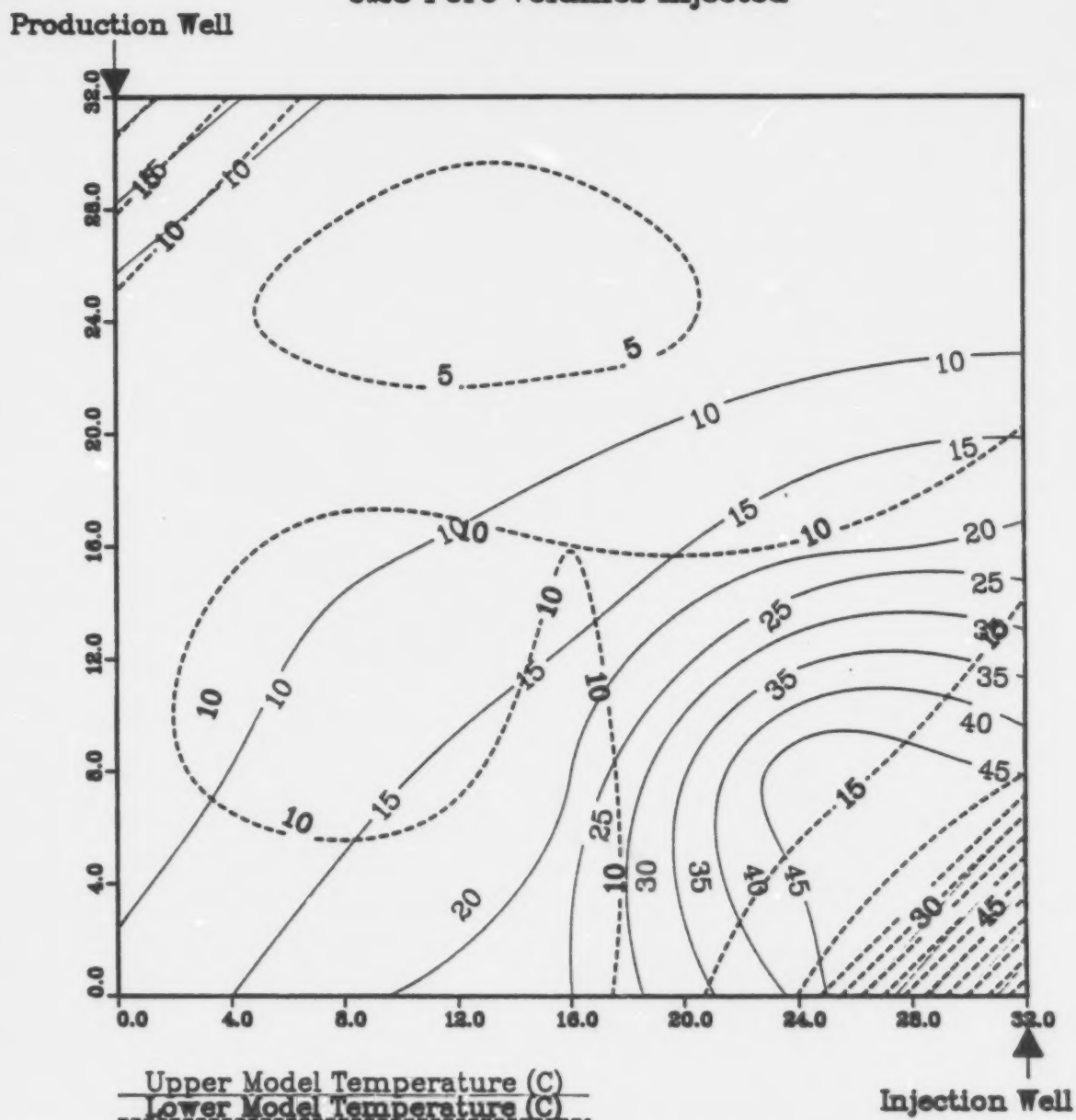


Figure A.48 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.50 Pore Volumes Injected

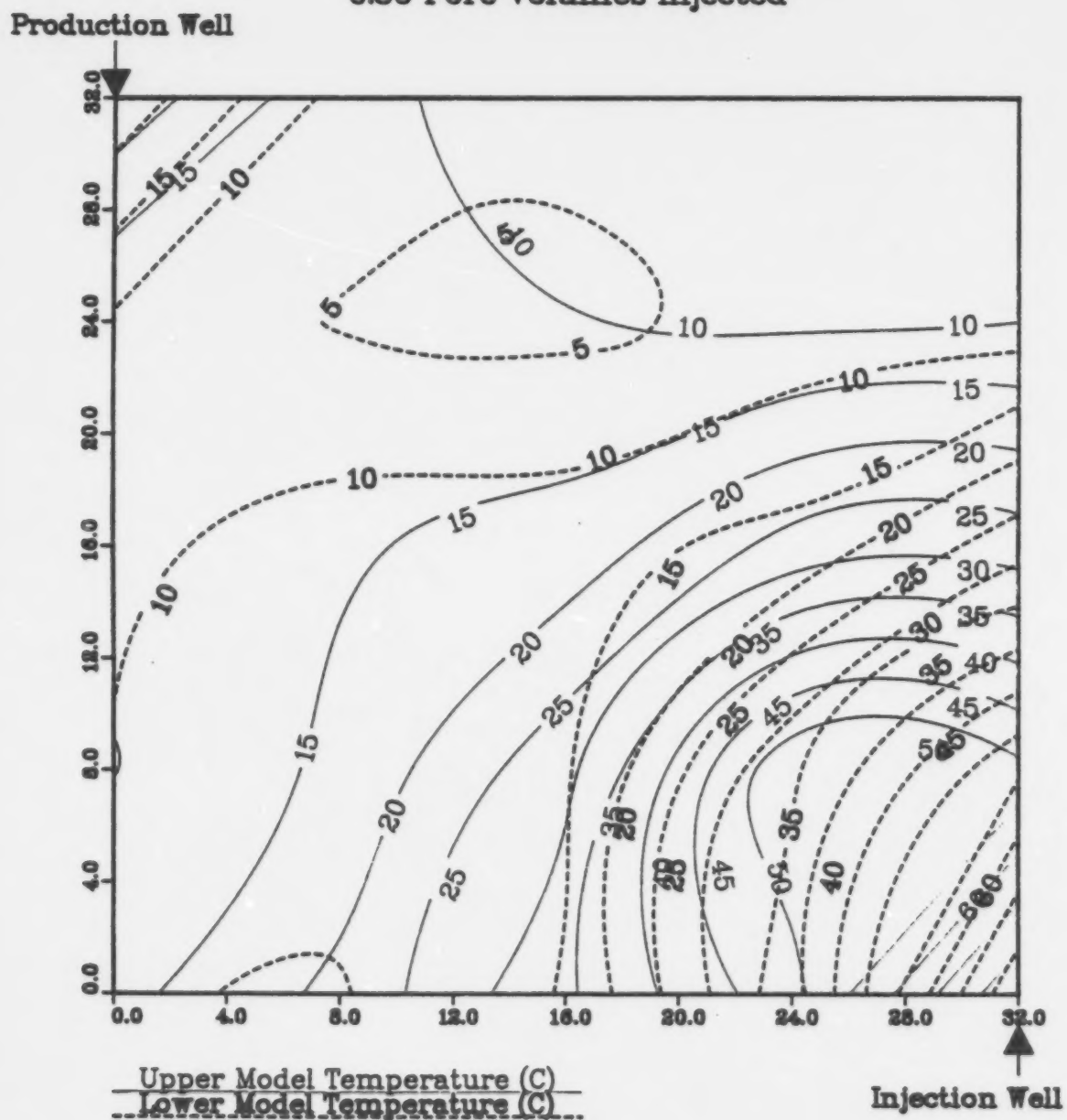


Figure A.49 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
0.75 Pore Volumes Injected

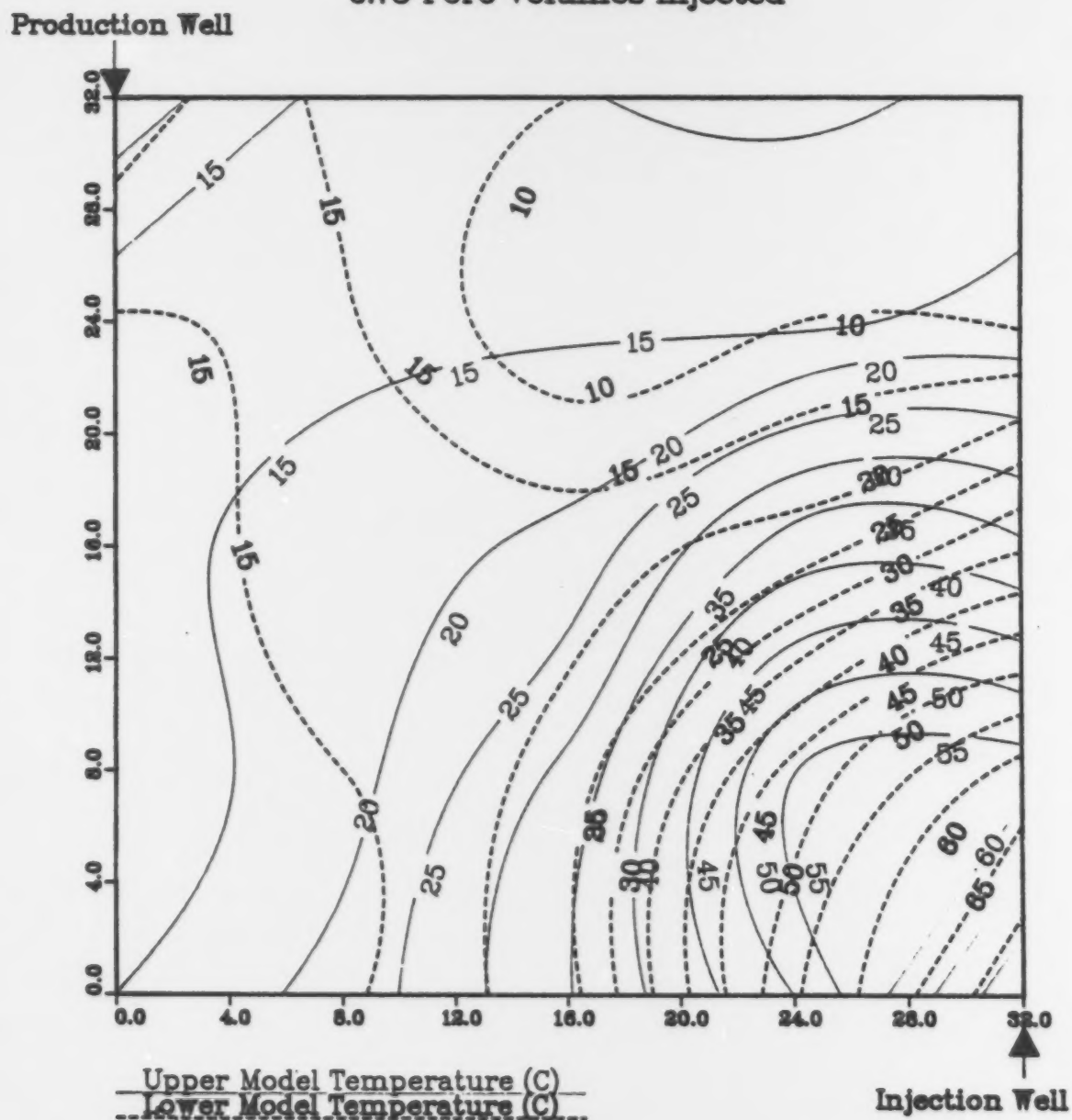


Figure A.50 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.00 Pore Volumes Injected

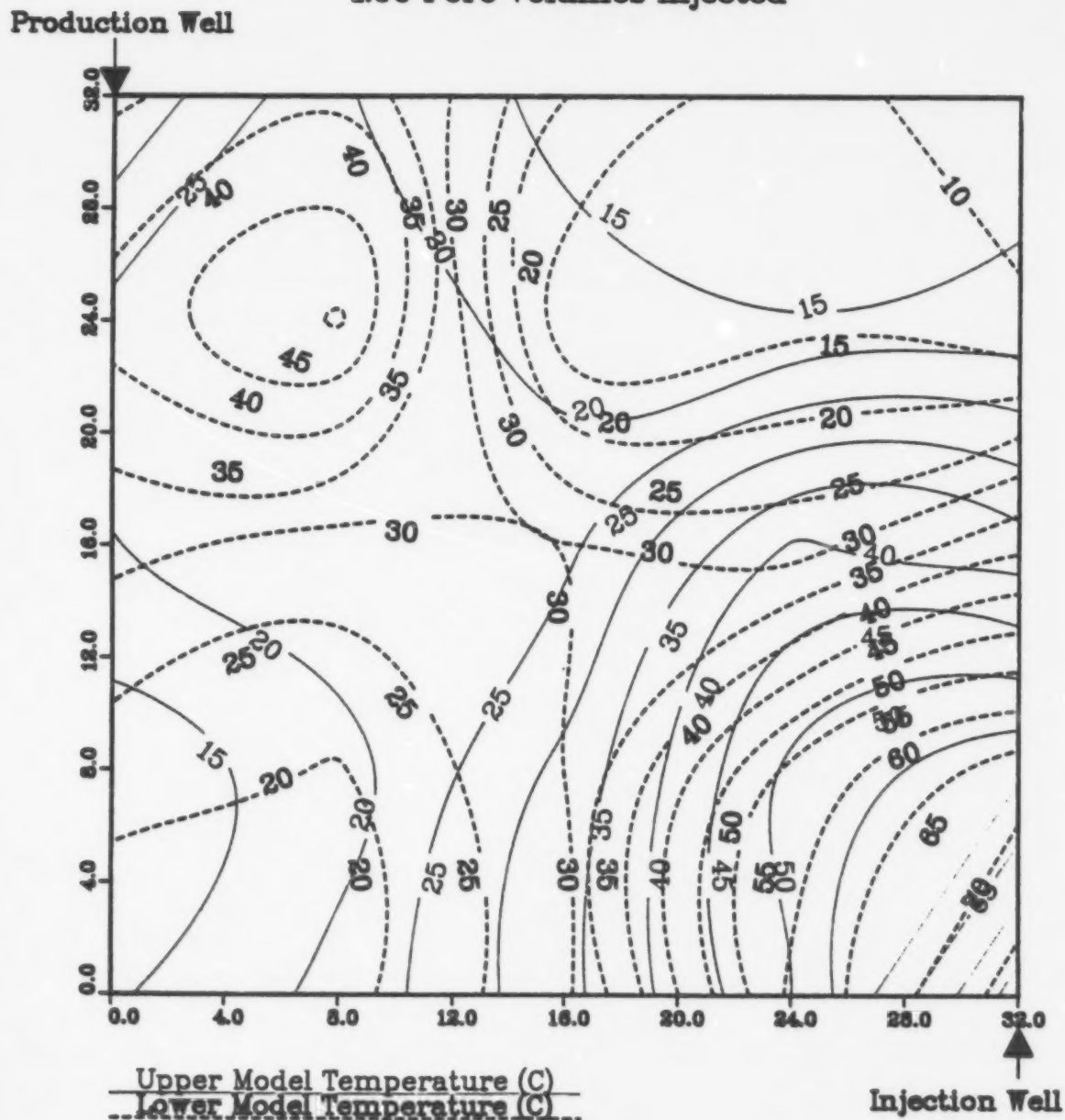


Figure A.51 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.25 Pore Volumes Injected

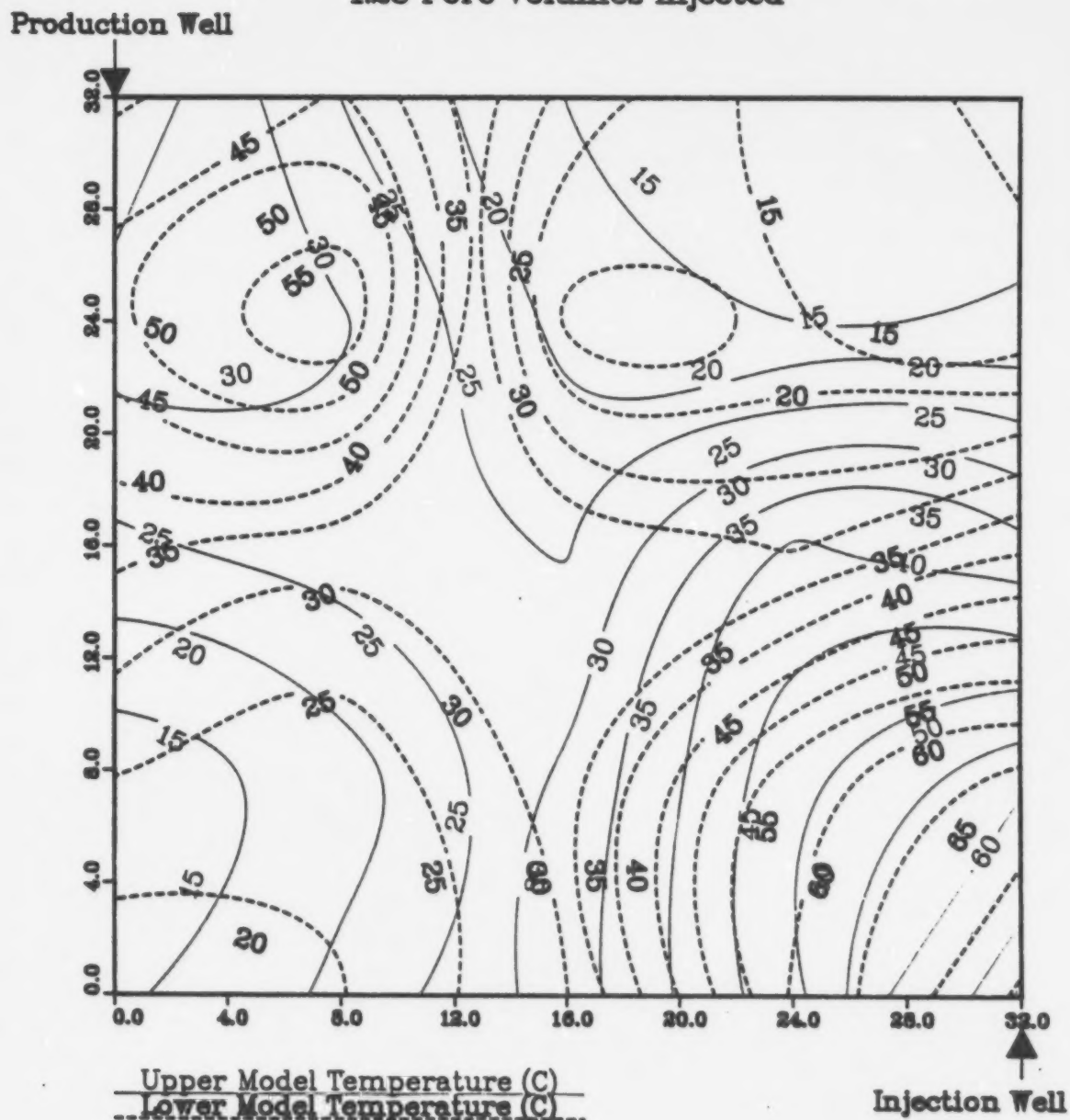
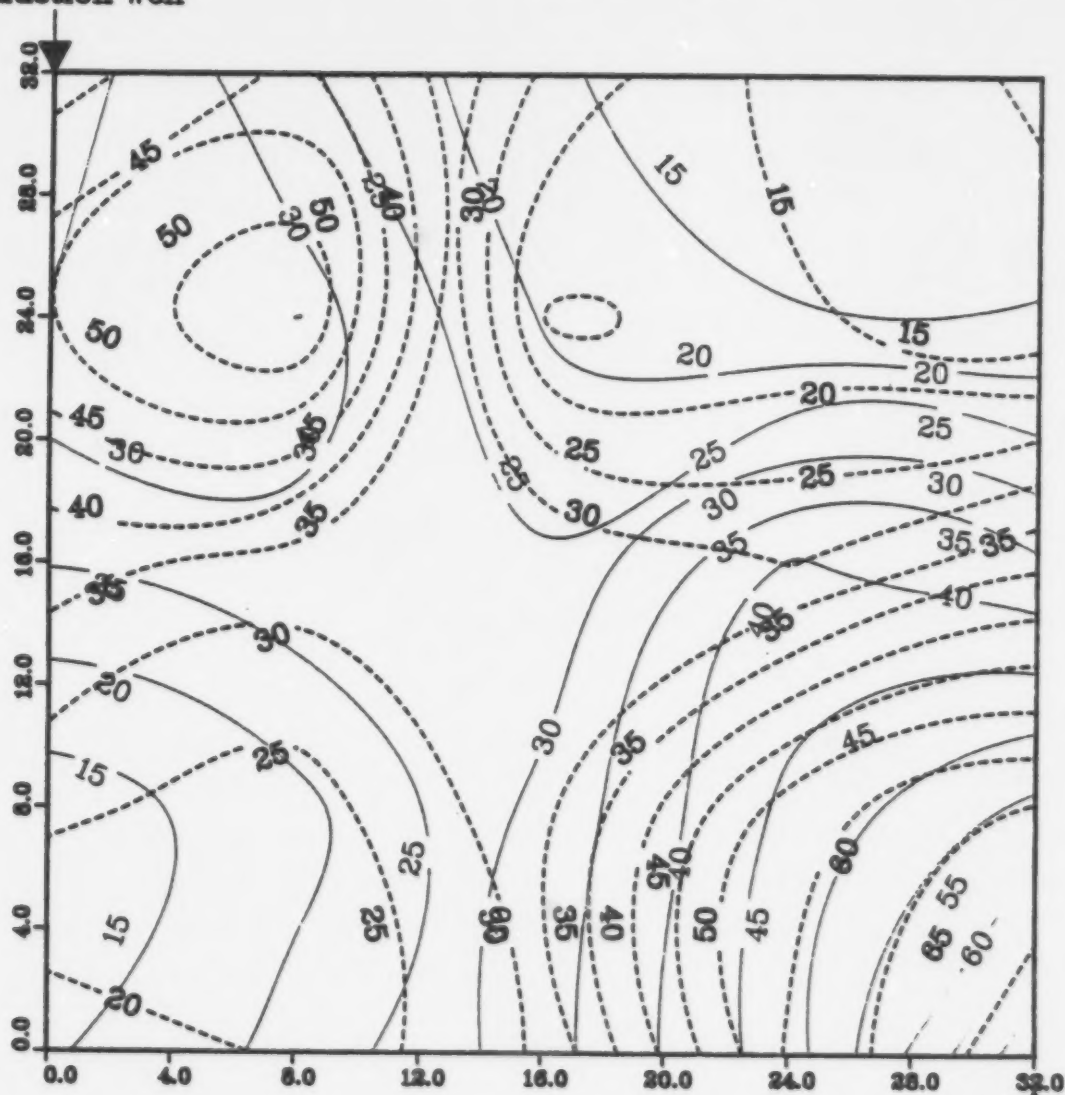


Figure A.52 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.53 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
1.75 Pore Volumes Injected

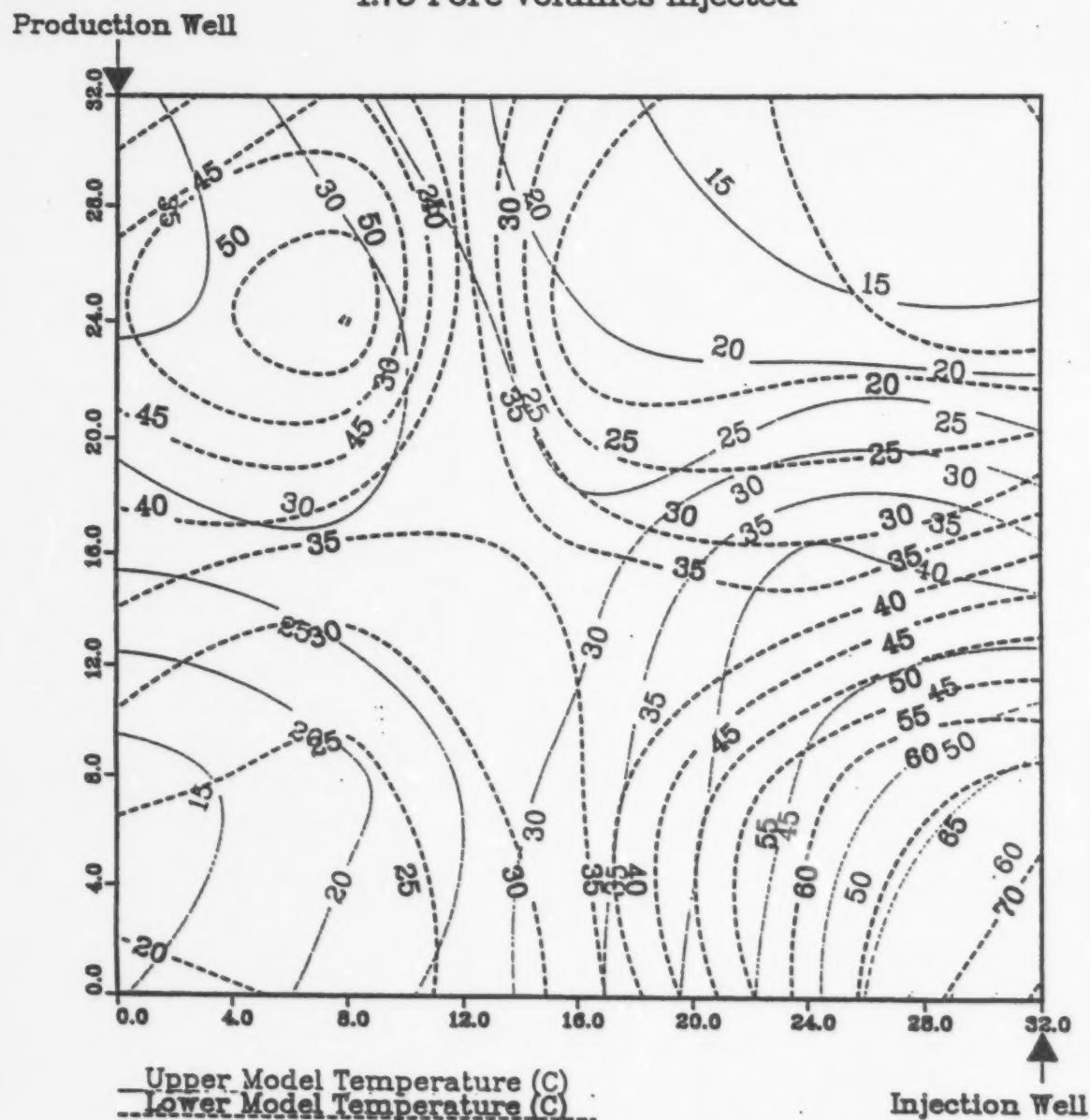
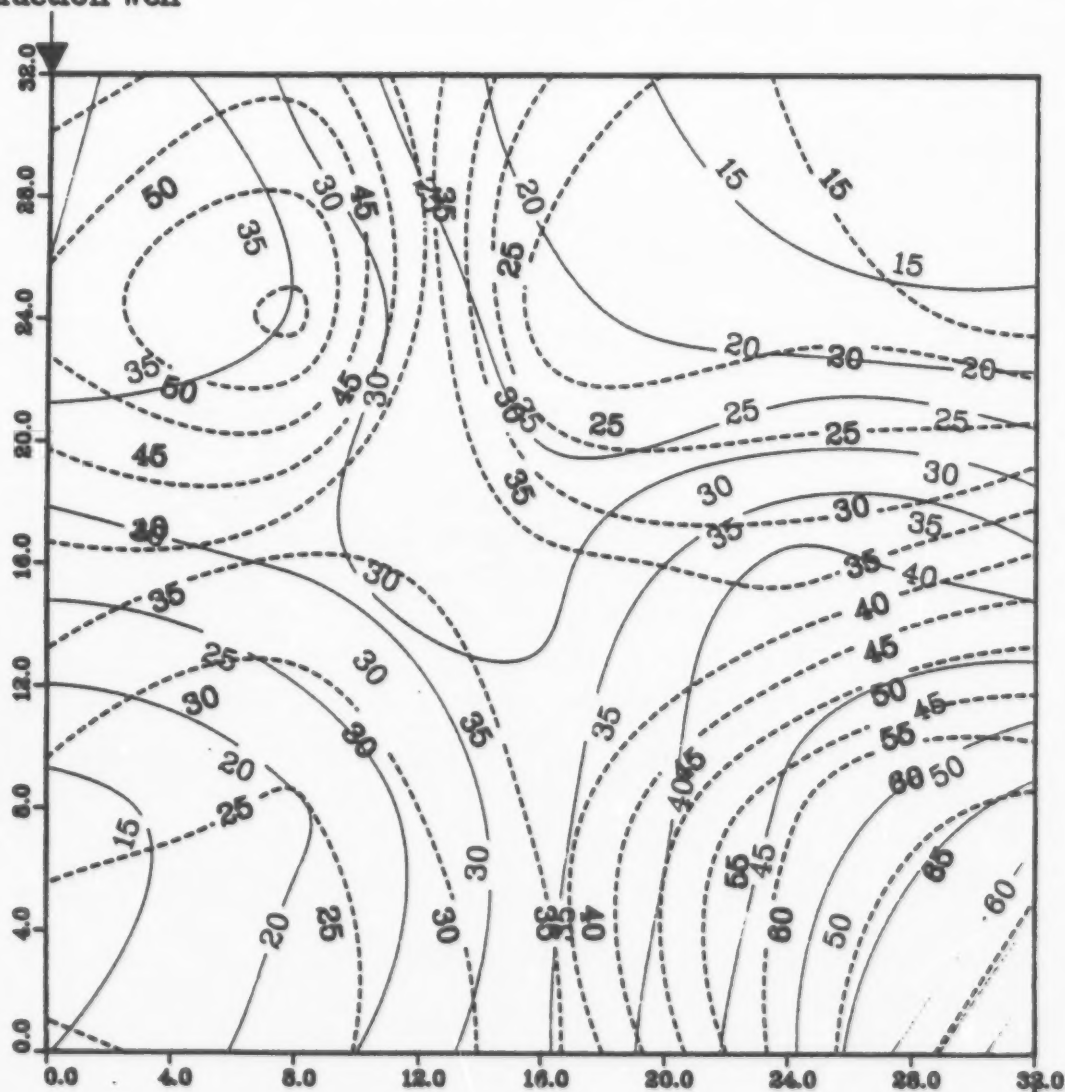


Figure A.54 : Run 46
Solvent-Steamflood in Homogeneous Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.55 :Run 46 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

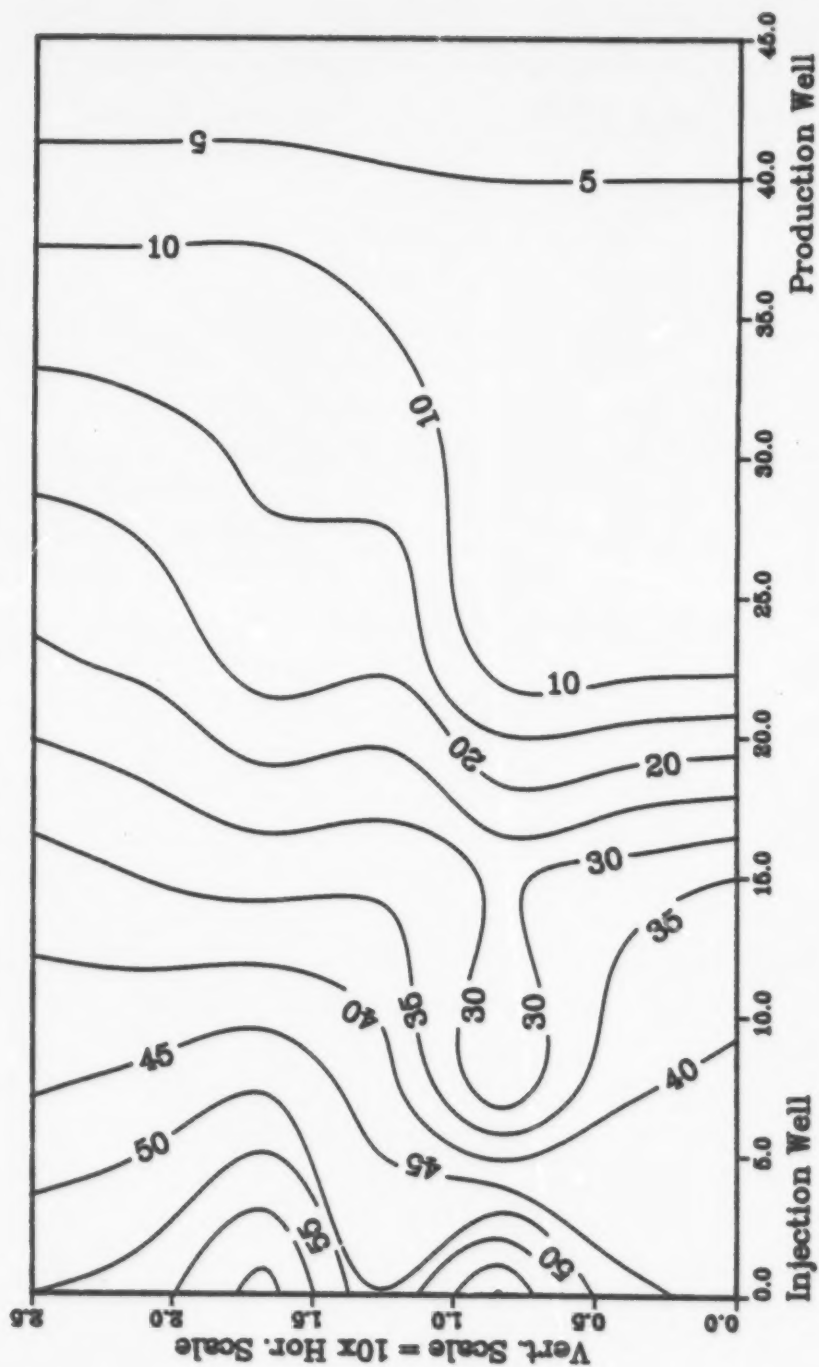


**Figure A.56 :Run 46 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

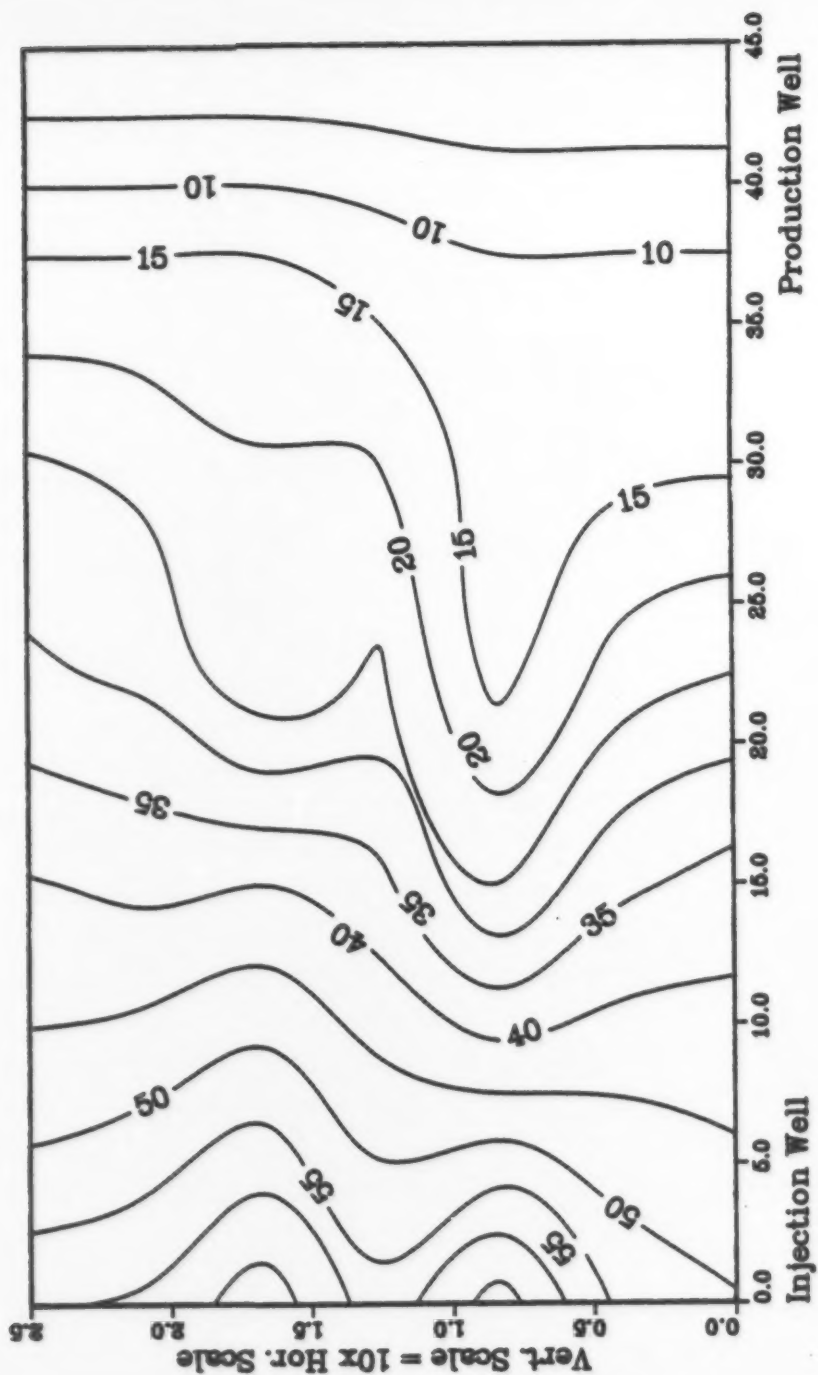


**Figure A.57 :Run 46 Temp Profile
Injector to Producer Cross-Section
0.76 Pore Volumes Injected.**

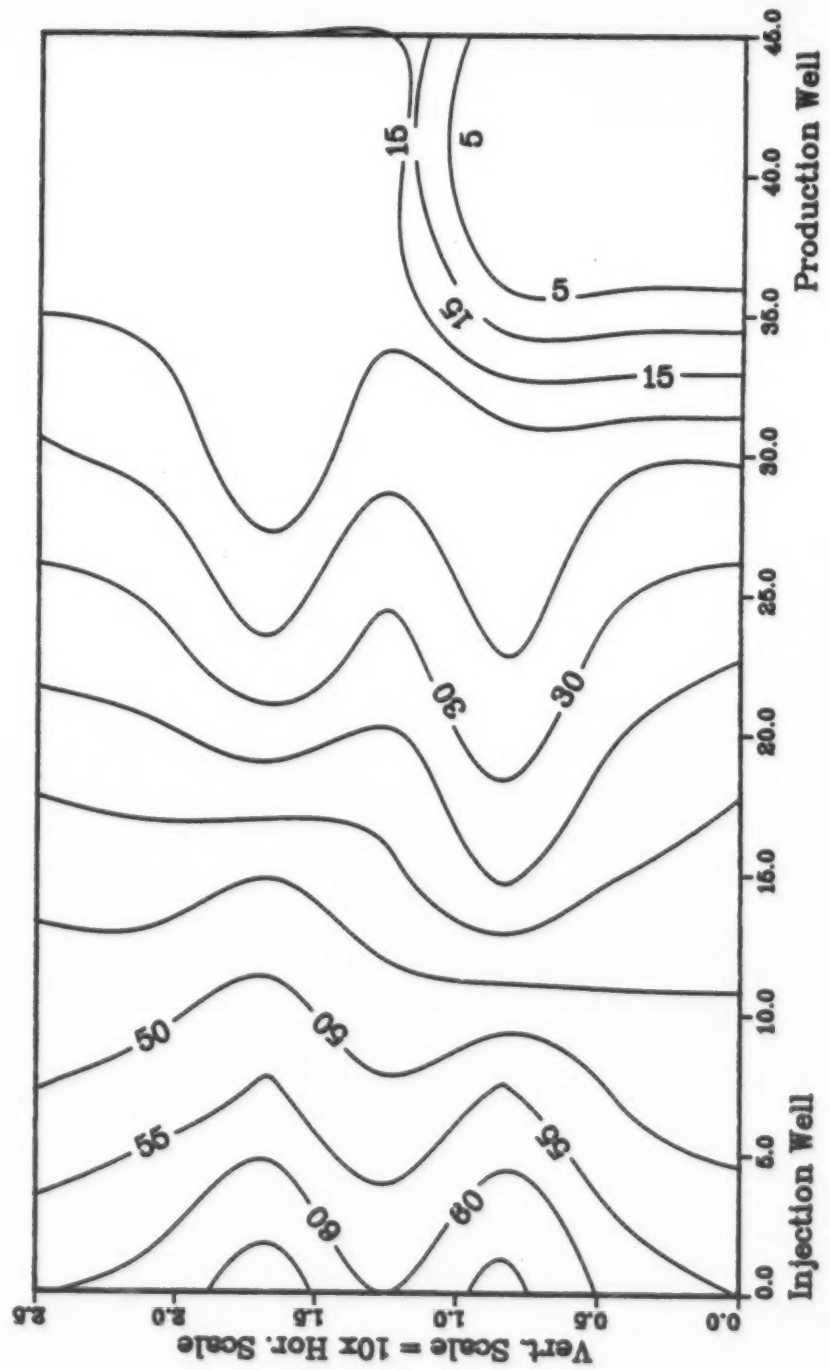


**Figure A58 :Run 46 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

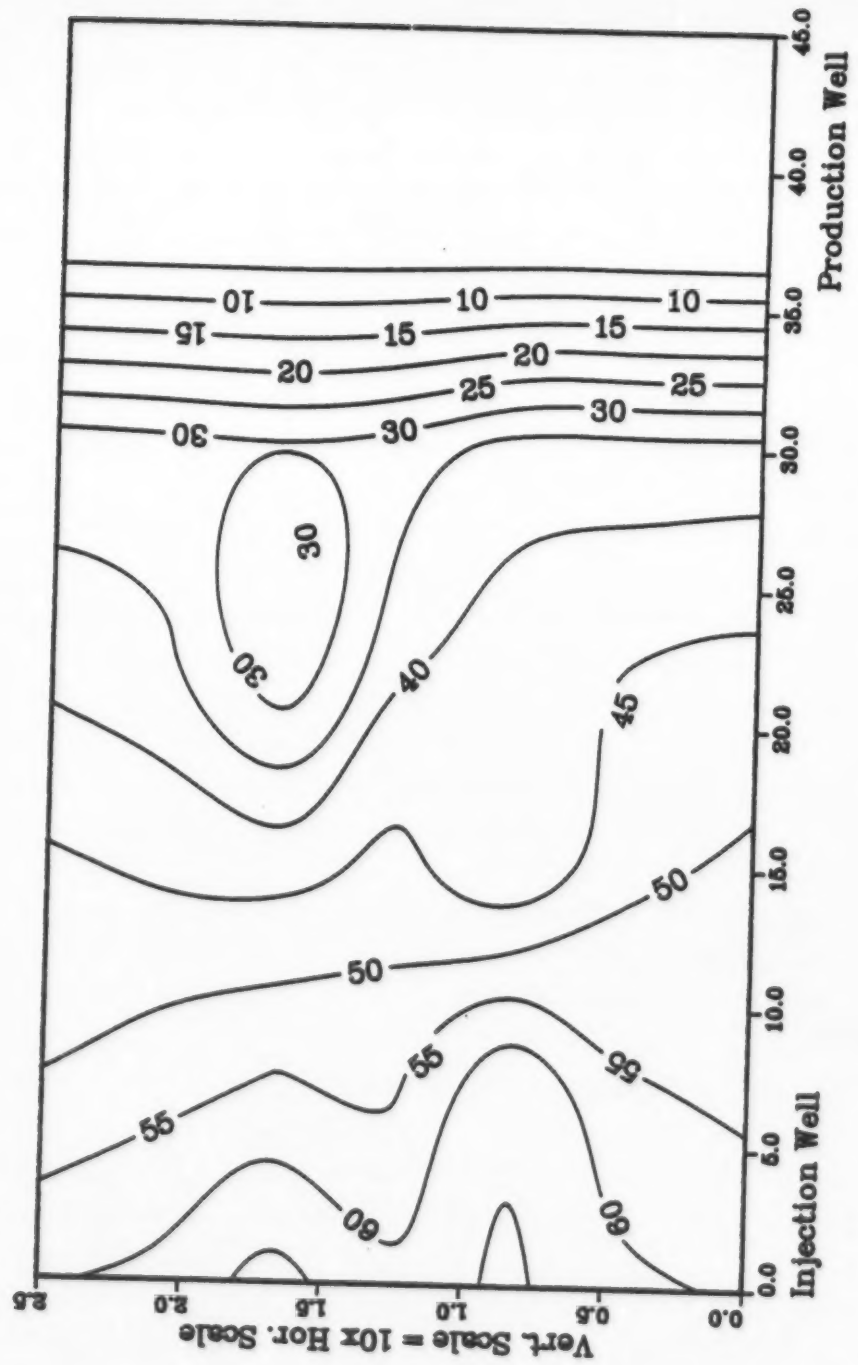


Figure A59 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

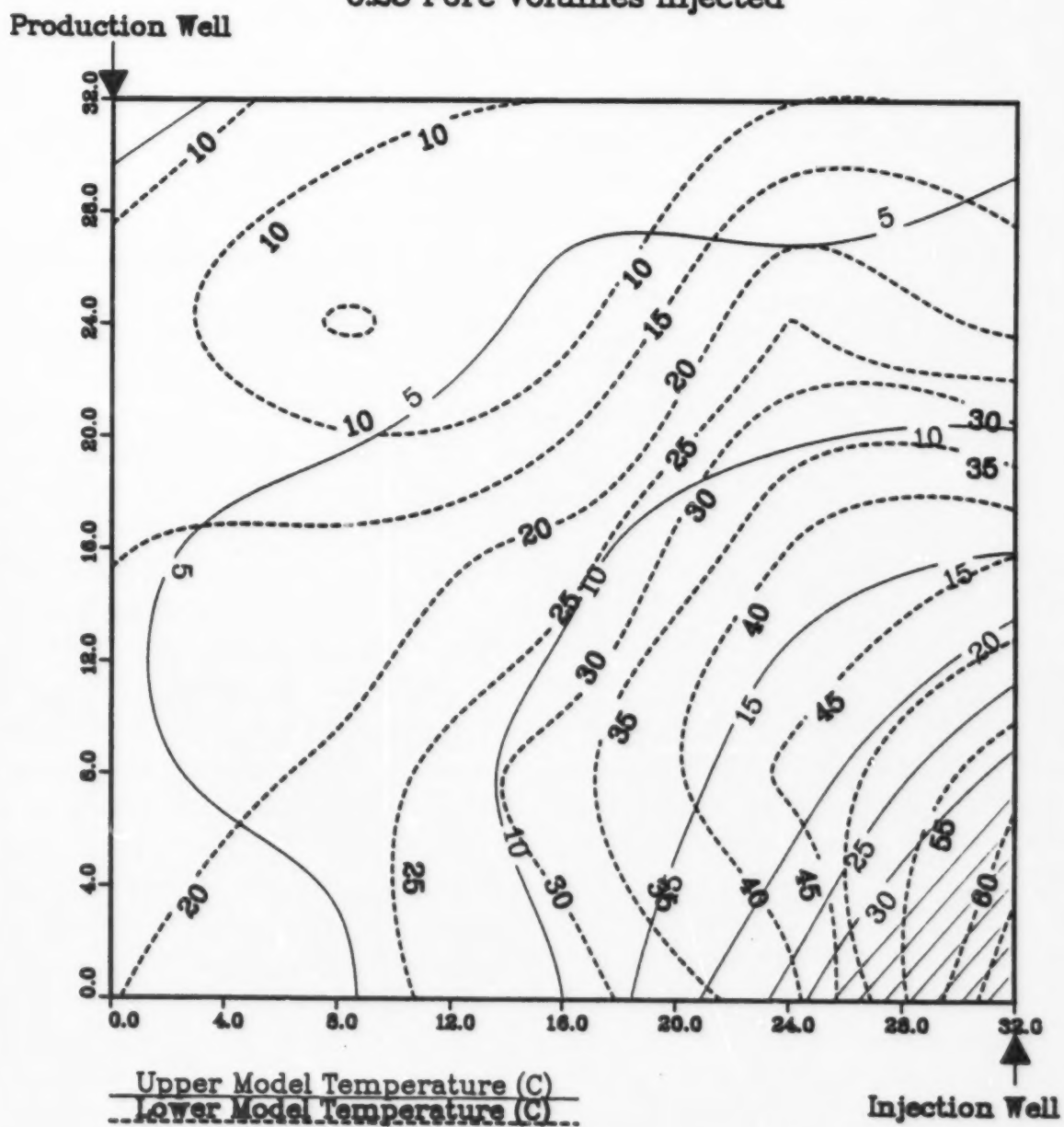


Figure A.60 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

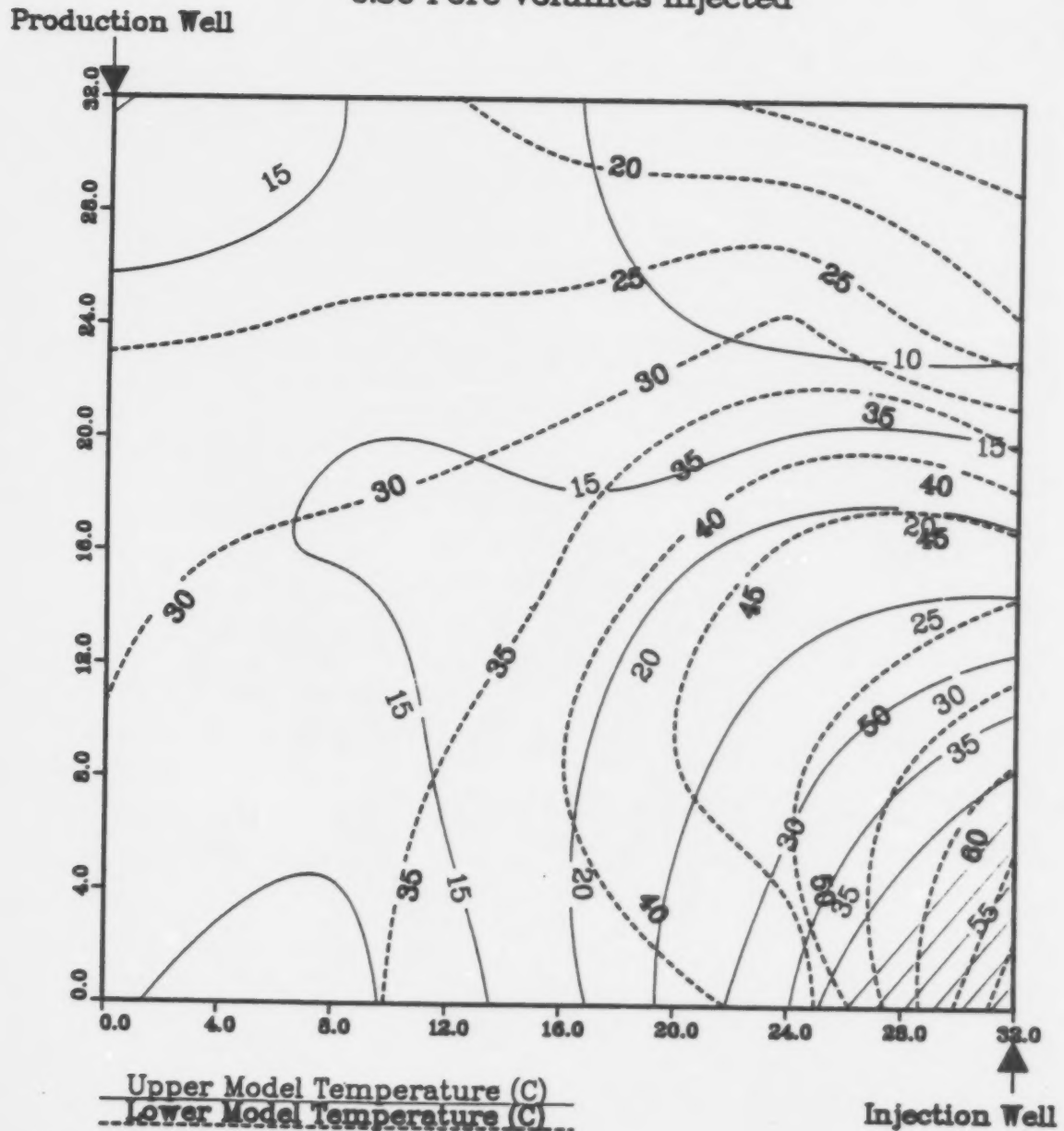


Figure A.61 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

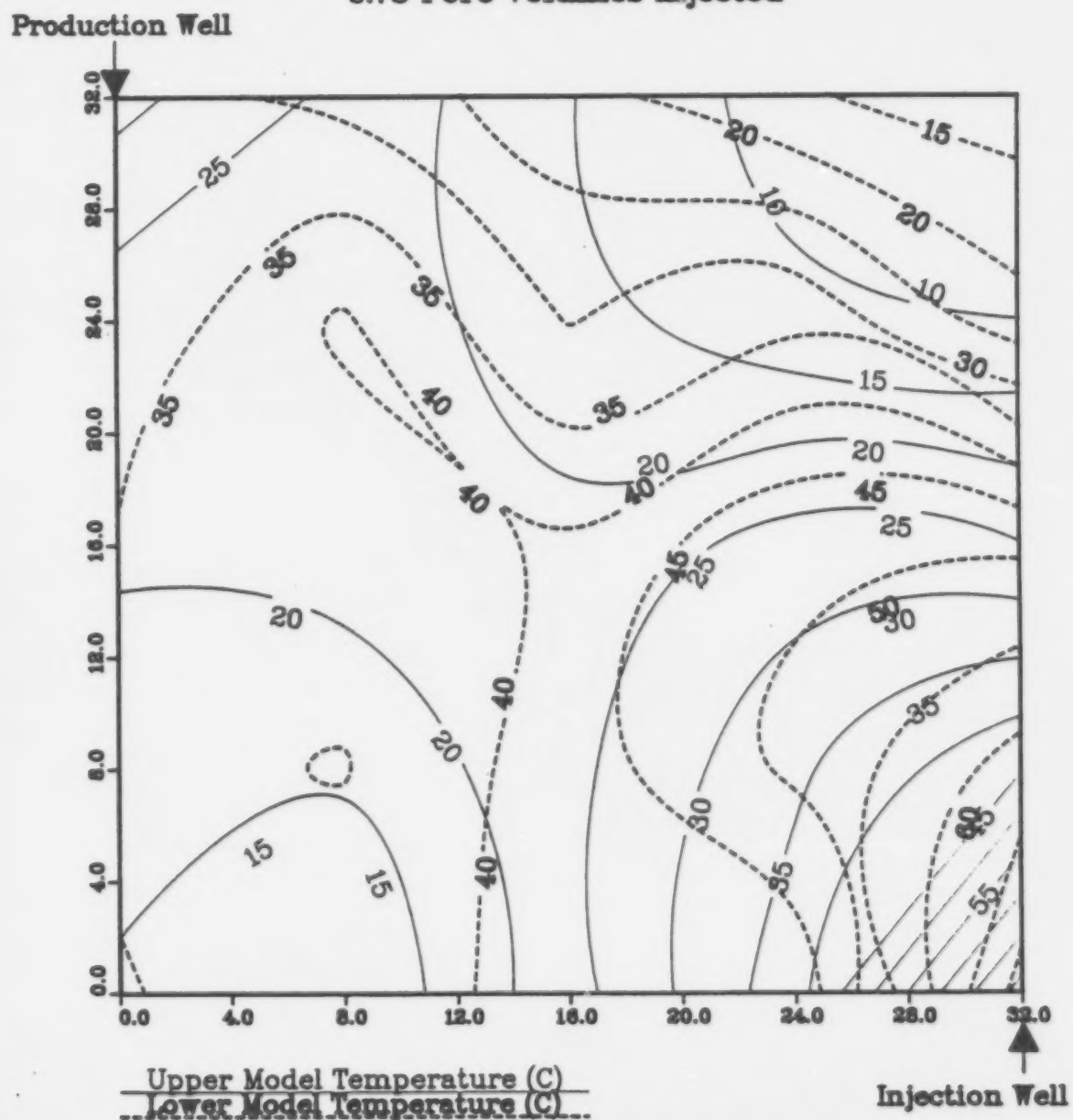


Figure A.62 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

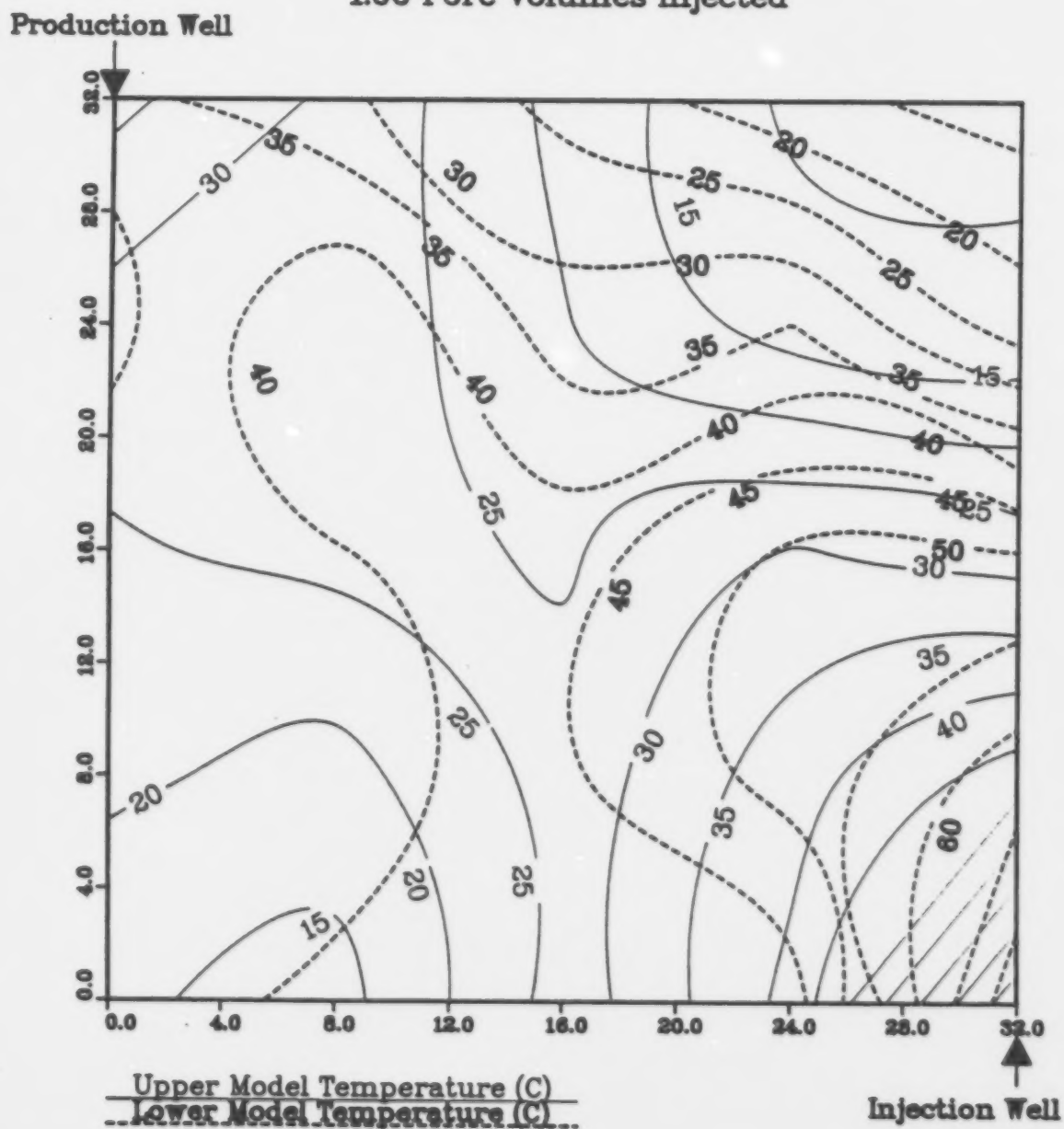


Figure A.63 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

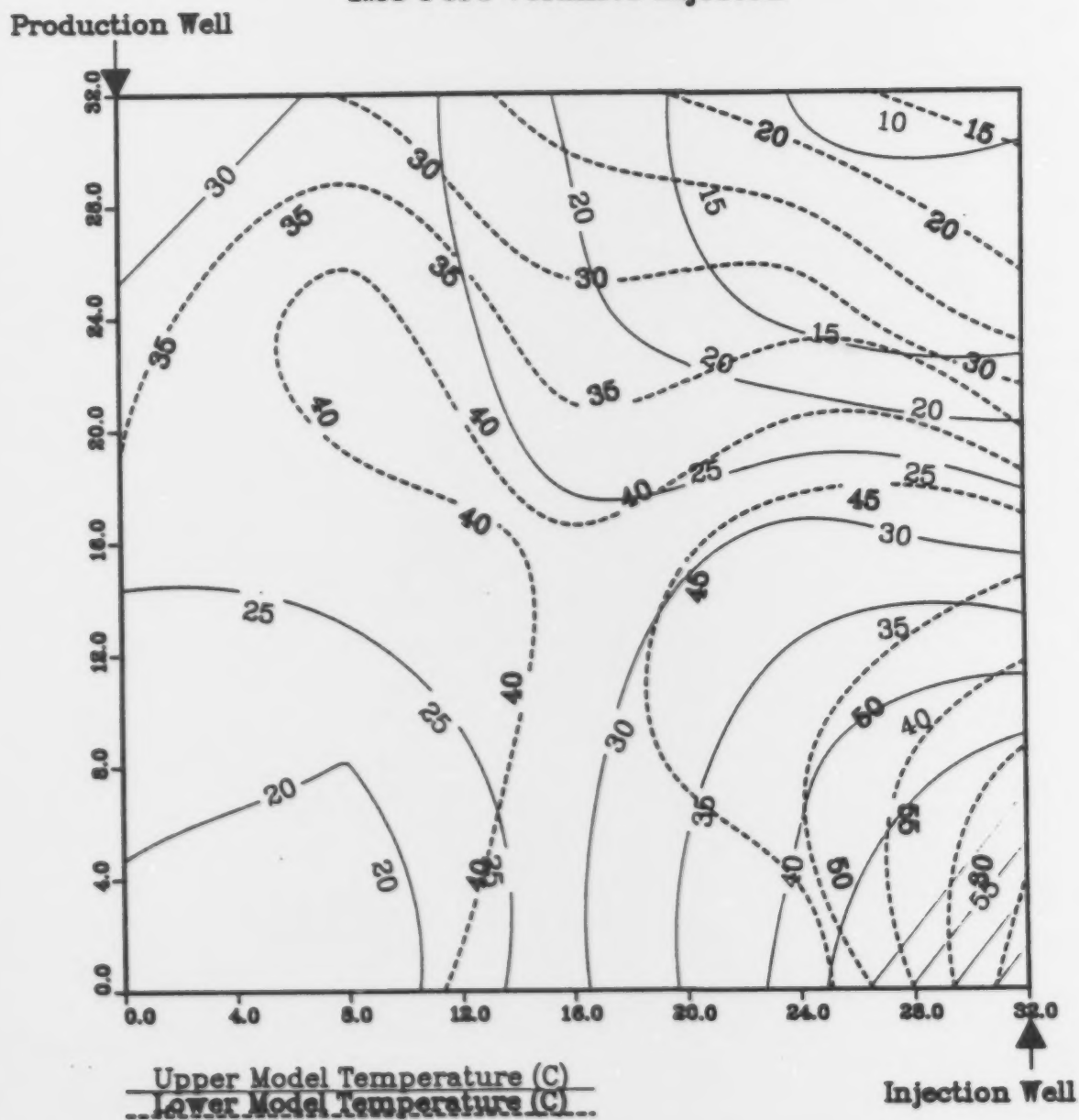


Figure A.64 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

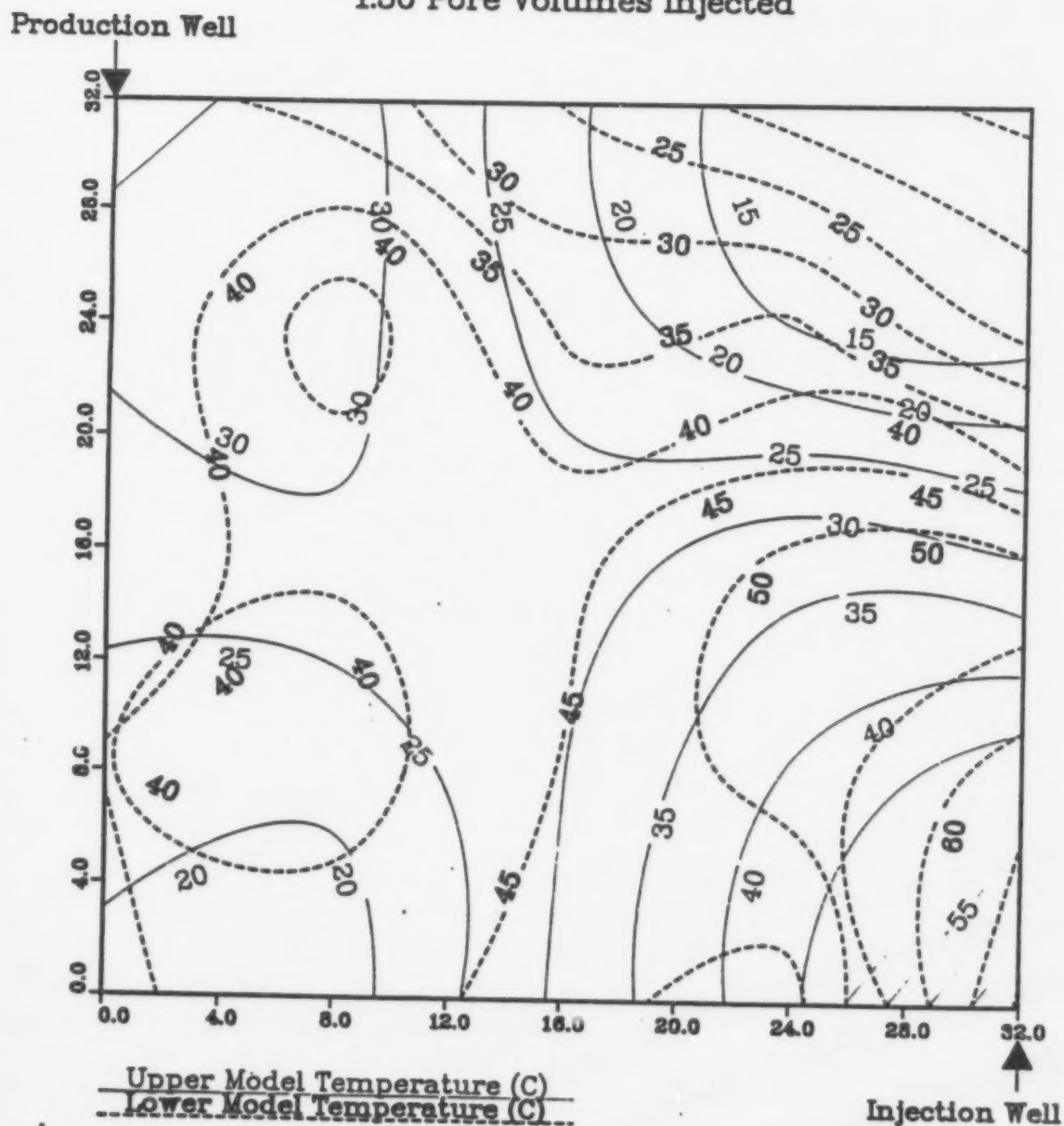
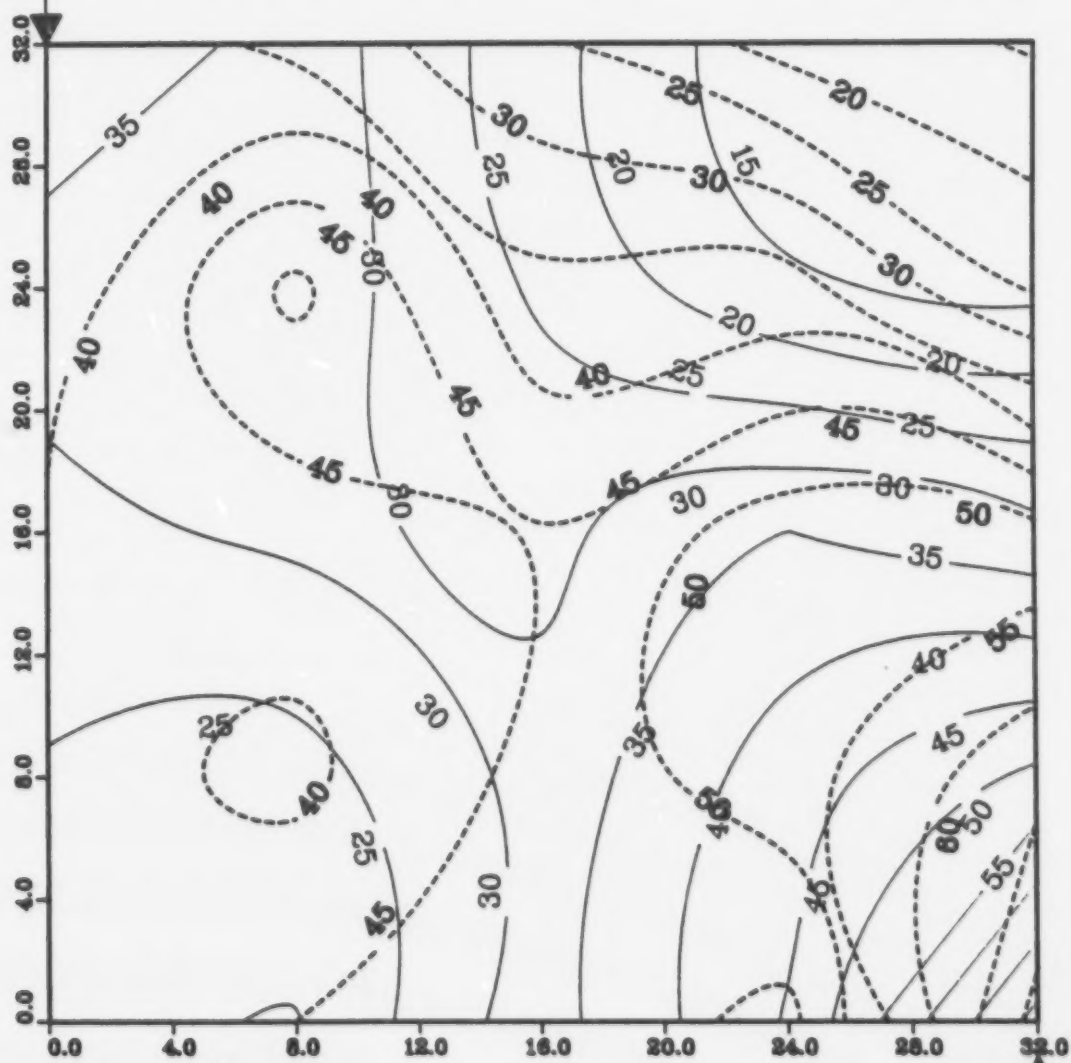


Figure A.65 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.66 : Run 60
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

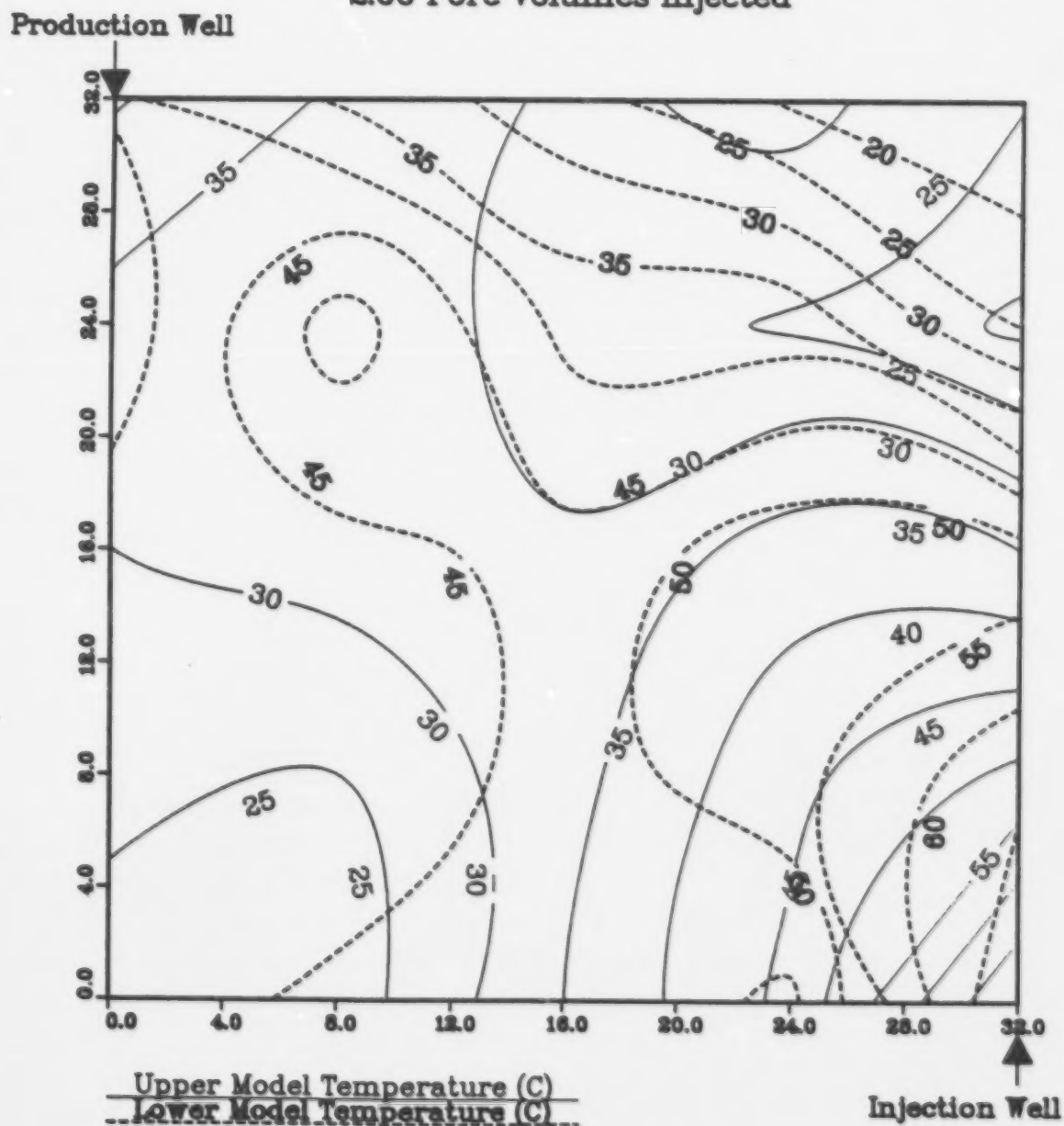


**Figure A.67 :Run 60 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

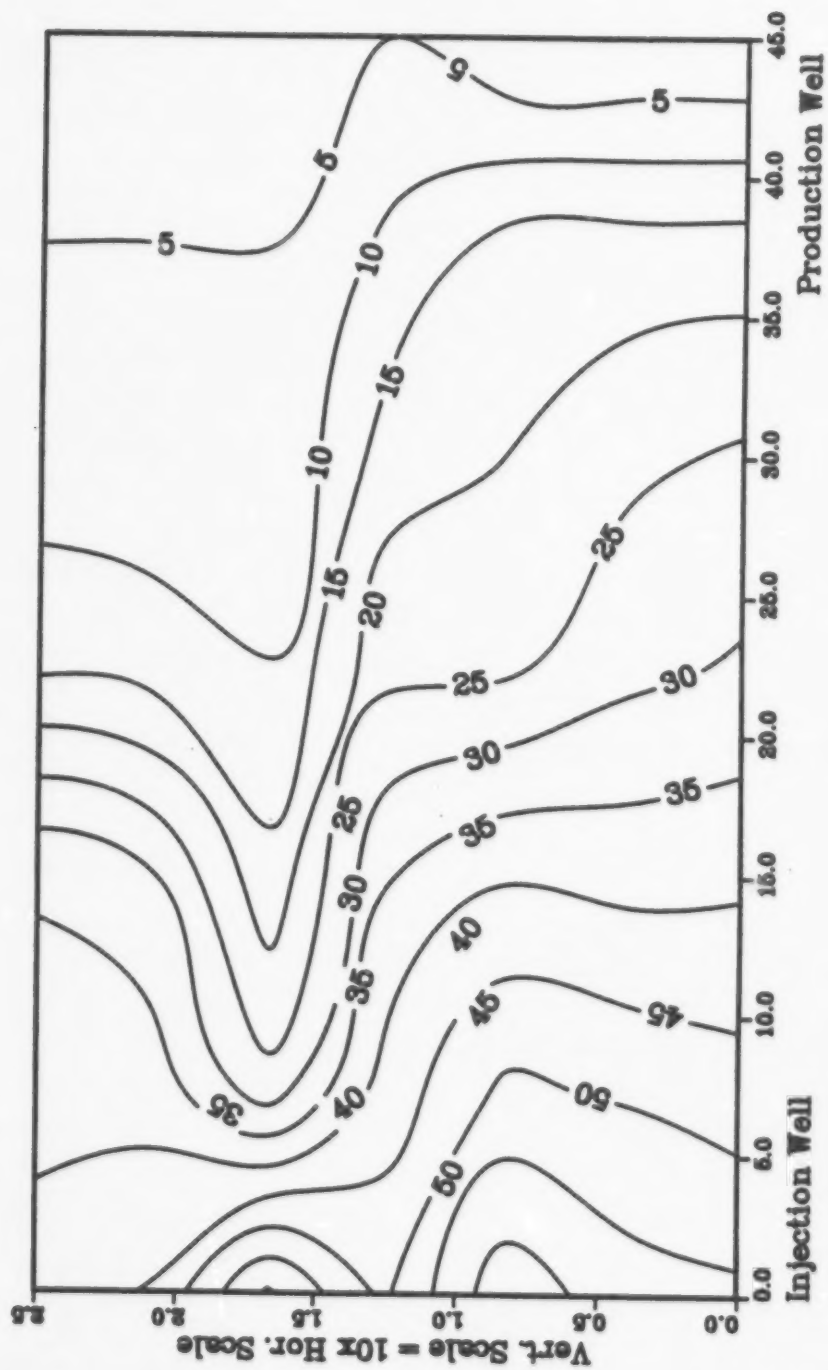


**Figure A.68 :Run 60 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

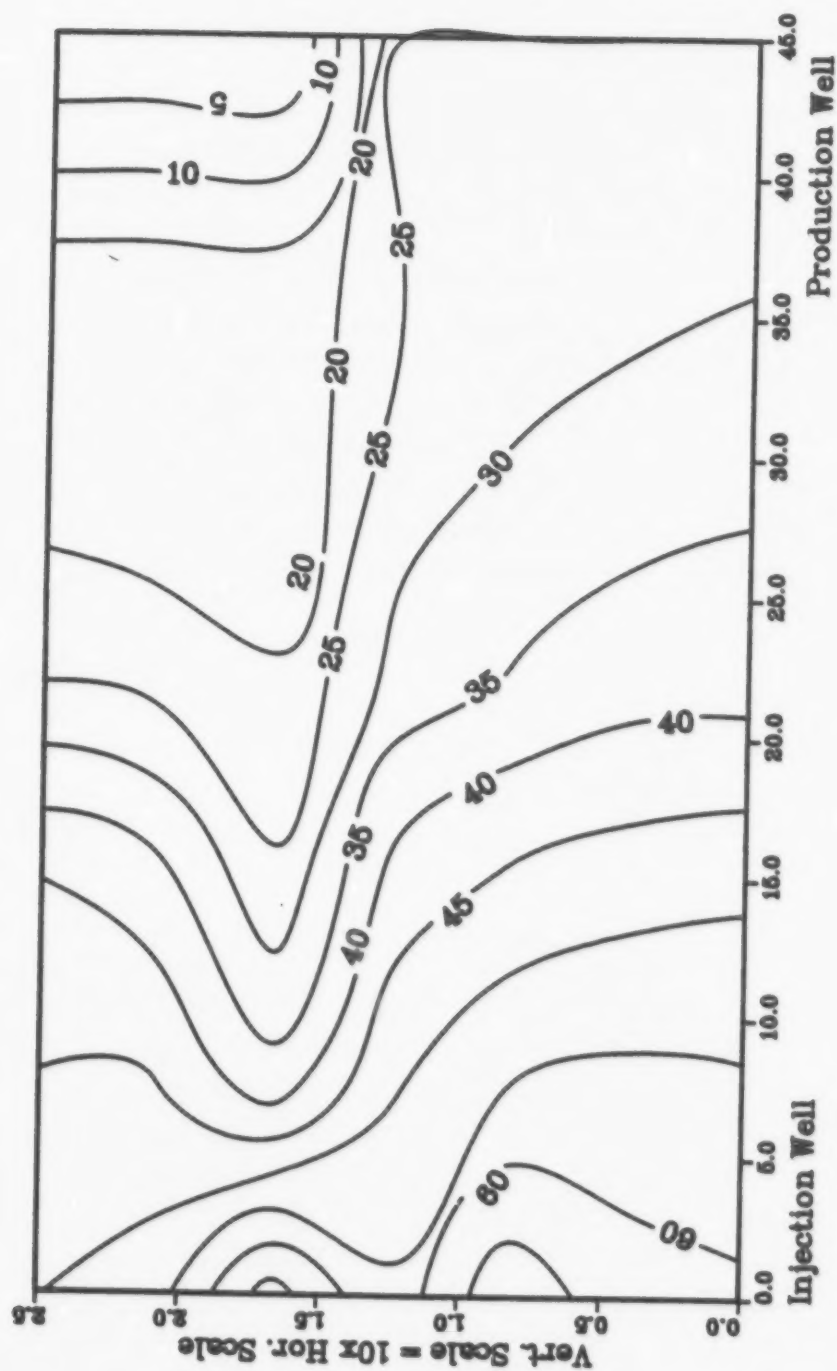


**Figure A.69 :Run 60 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

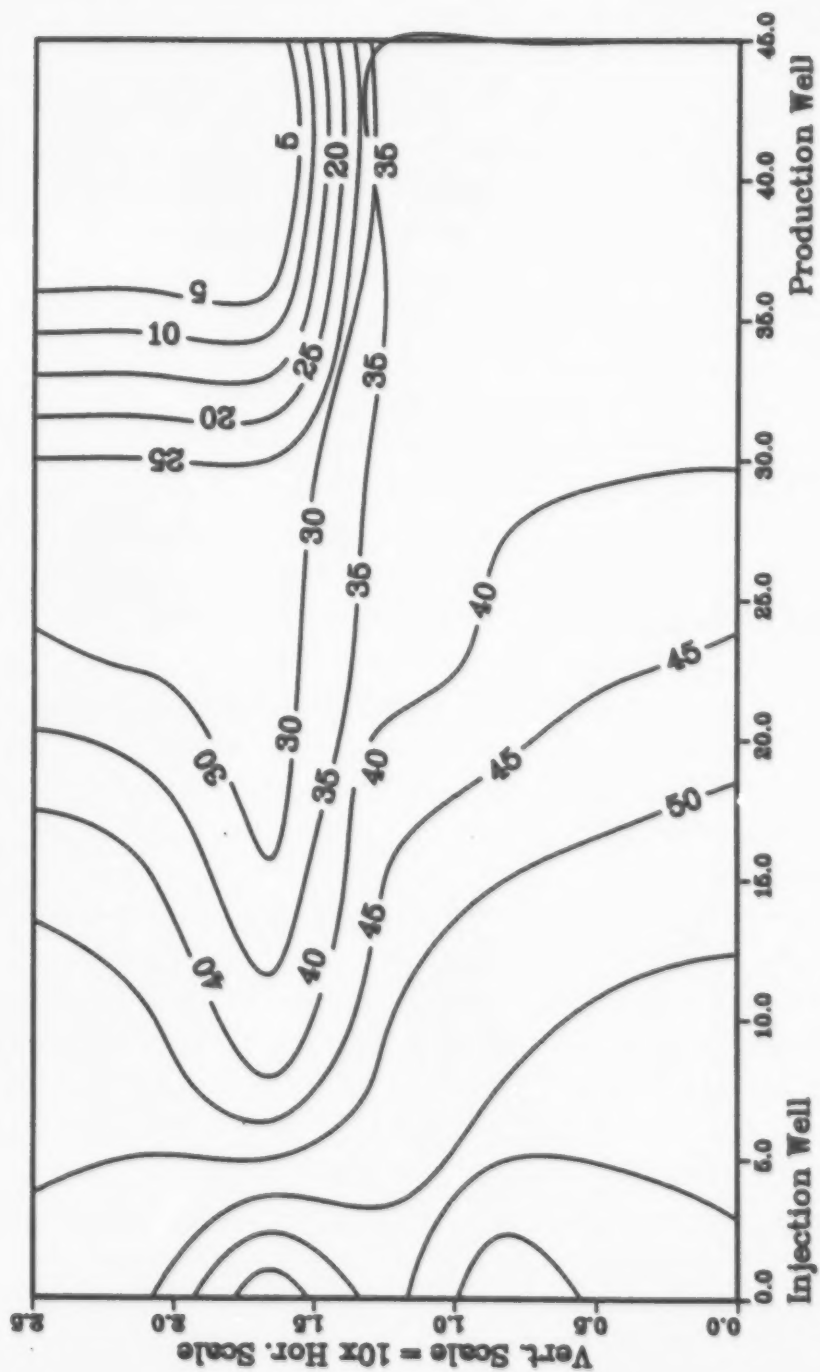


**Figure A.70 :Run 60 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

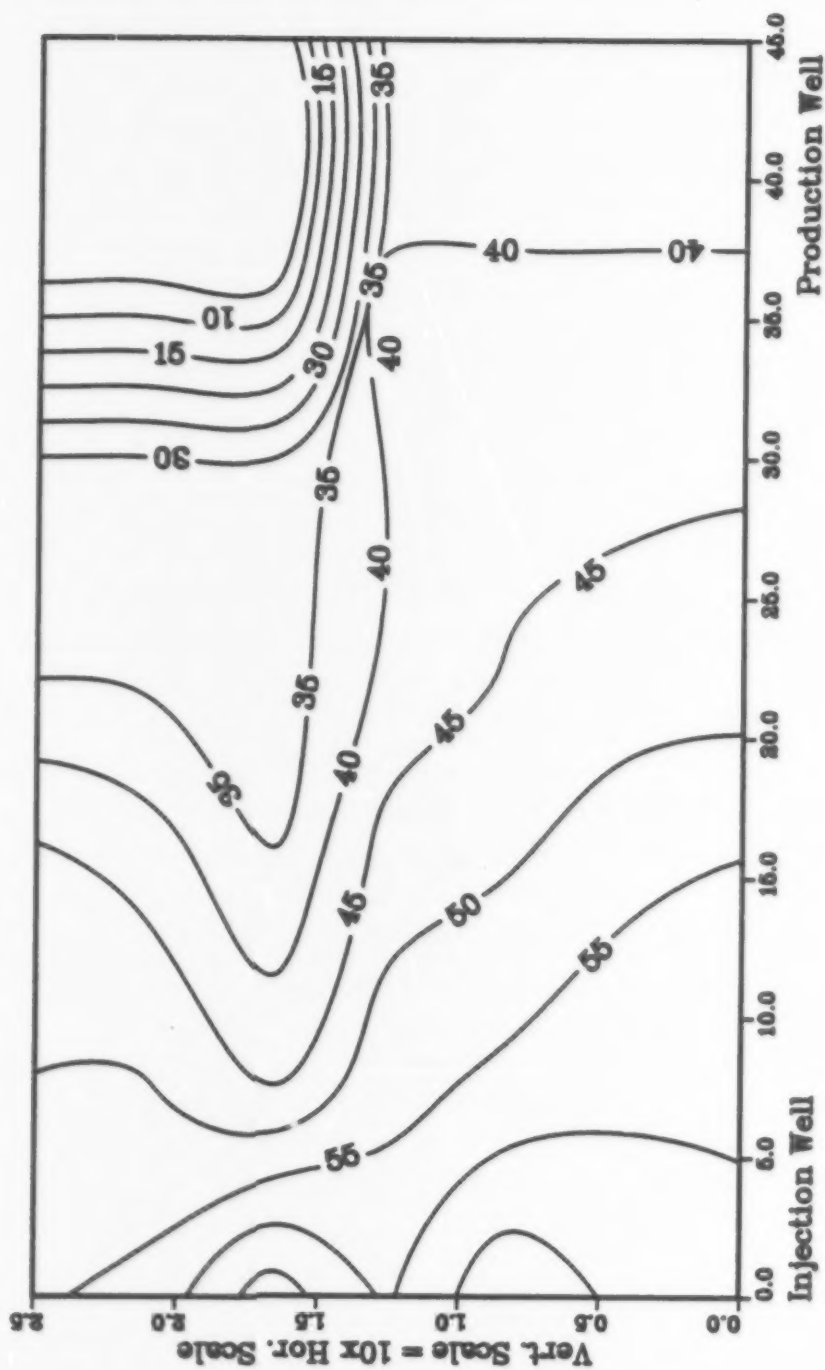


Figure A.71 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

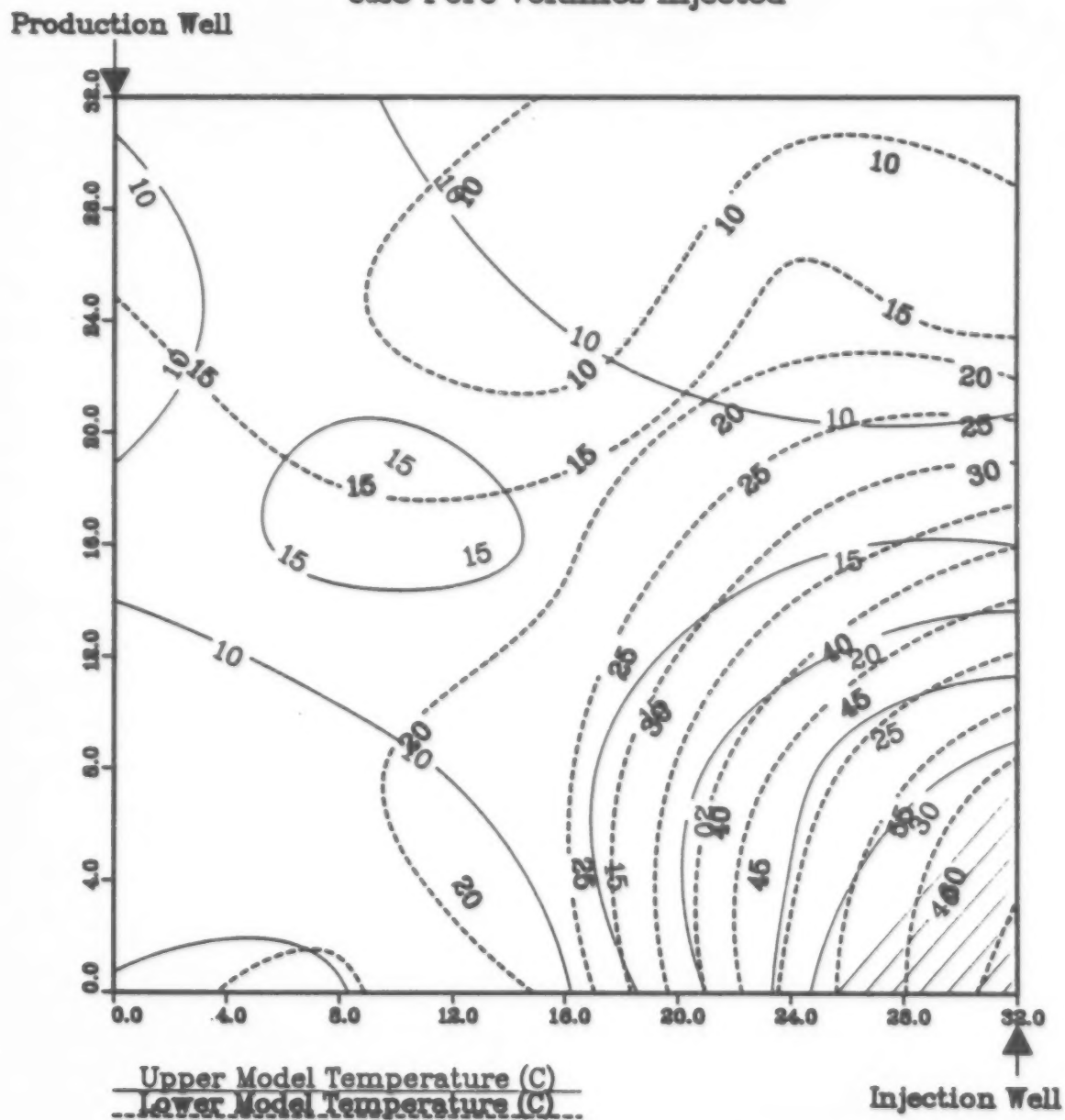
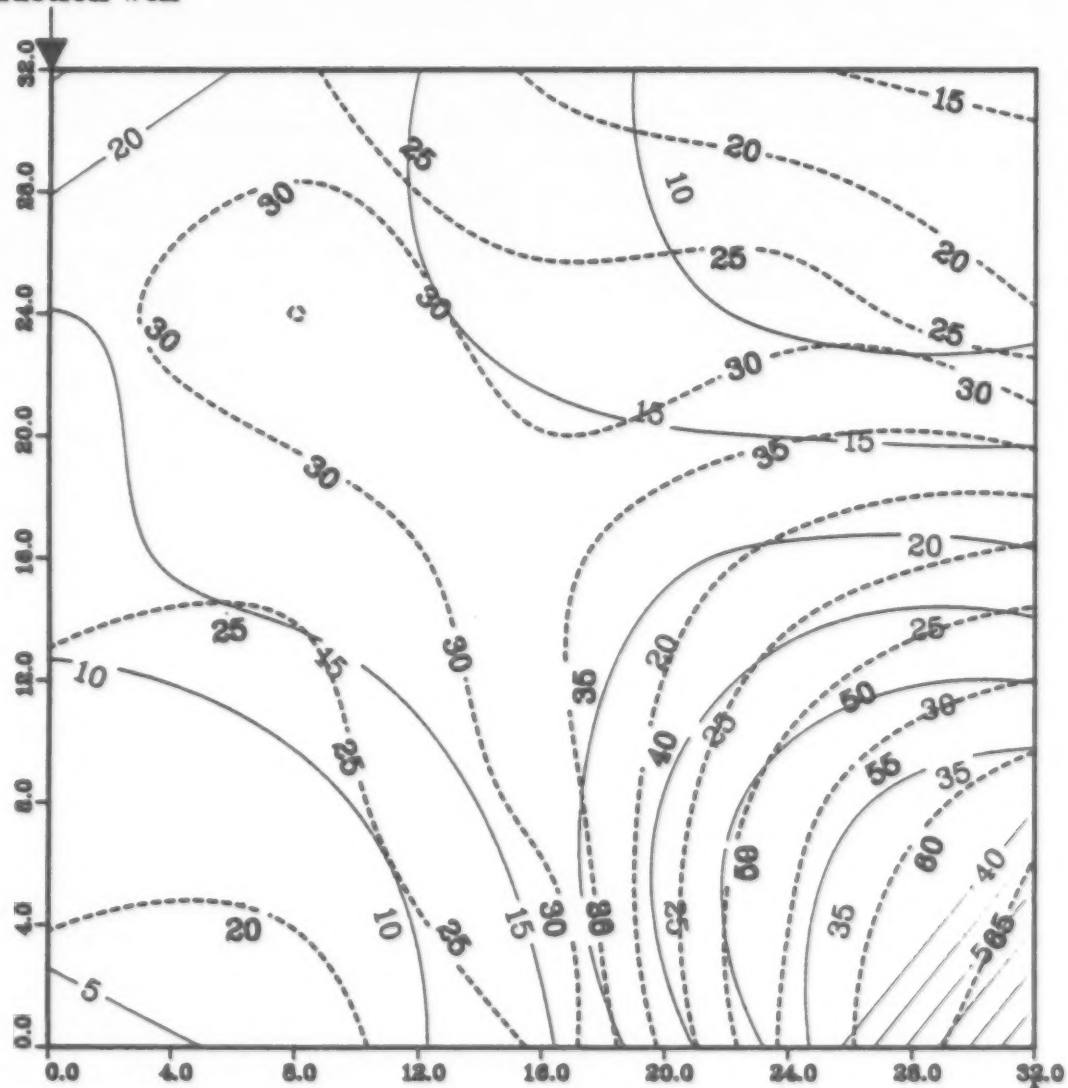


Figure A.72 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



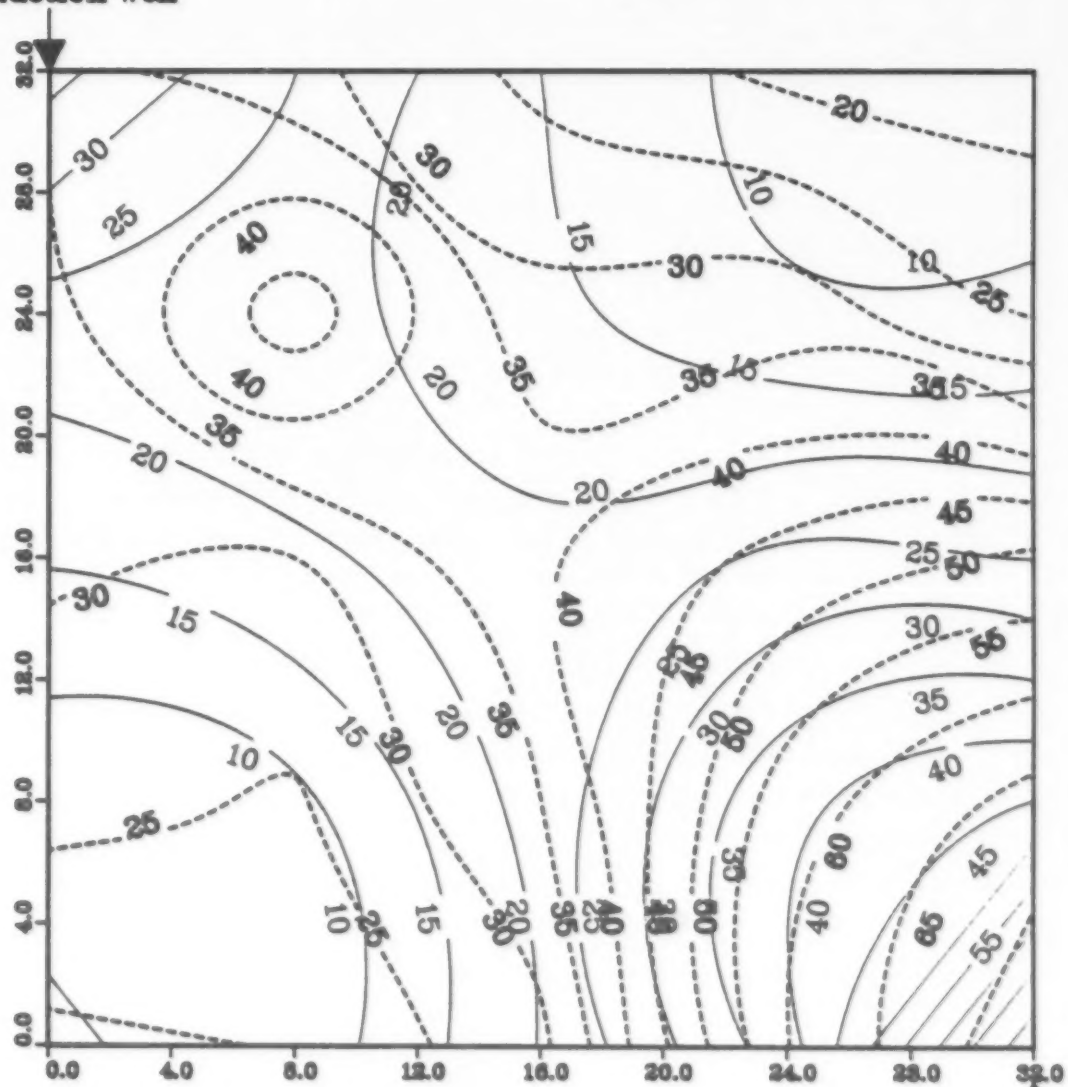
Upper Model Temperature (C)
... Lower Model Temperature (C) ...

Injection Well

Figure A.73 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
--- Lower Model Temperature (C) ---

Injection Well

Figure A.74 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

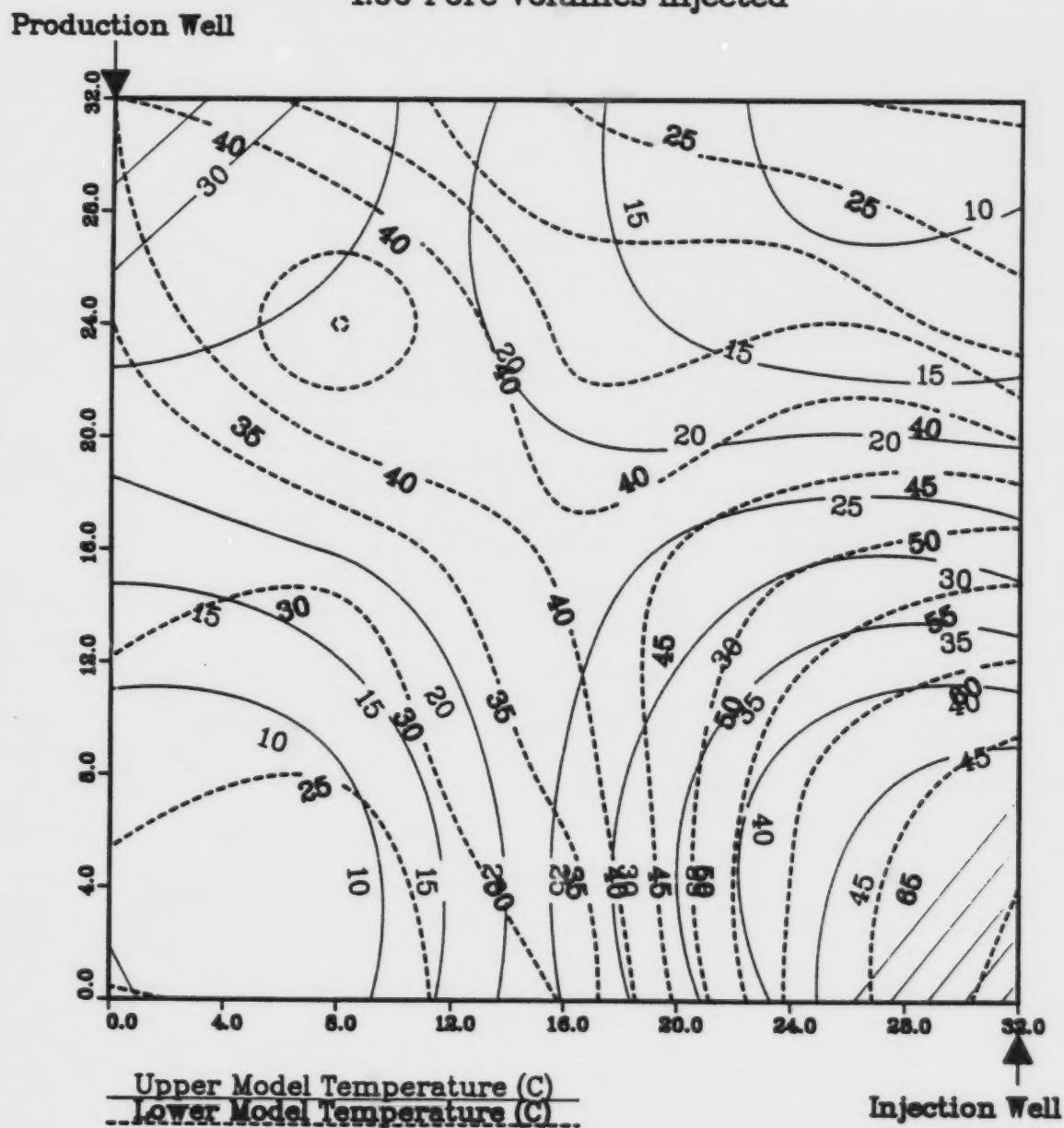
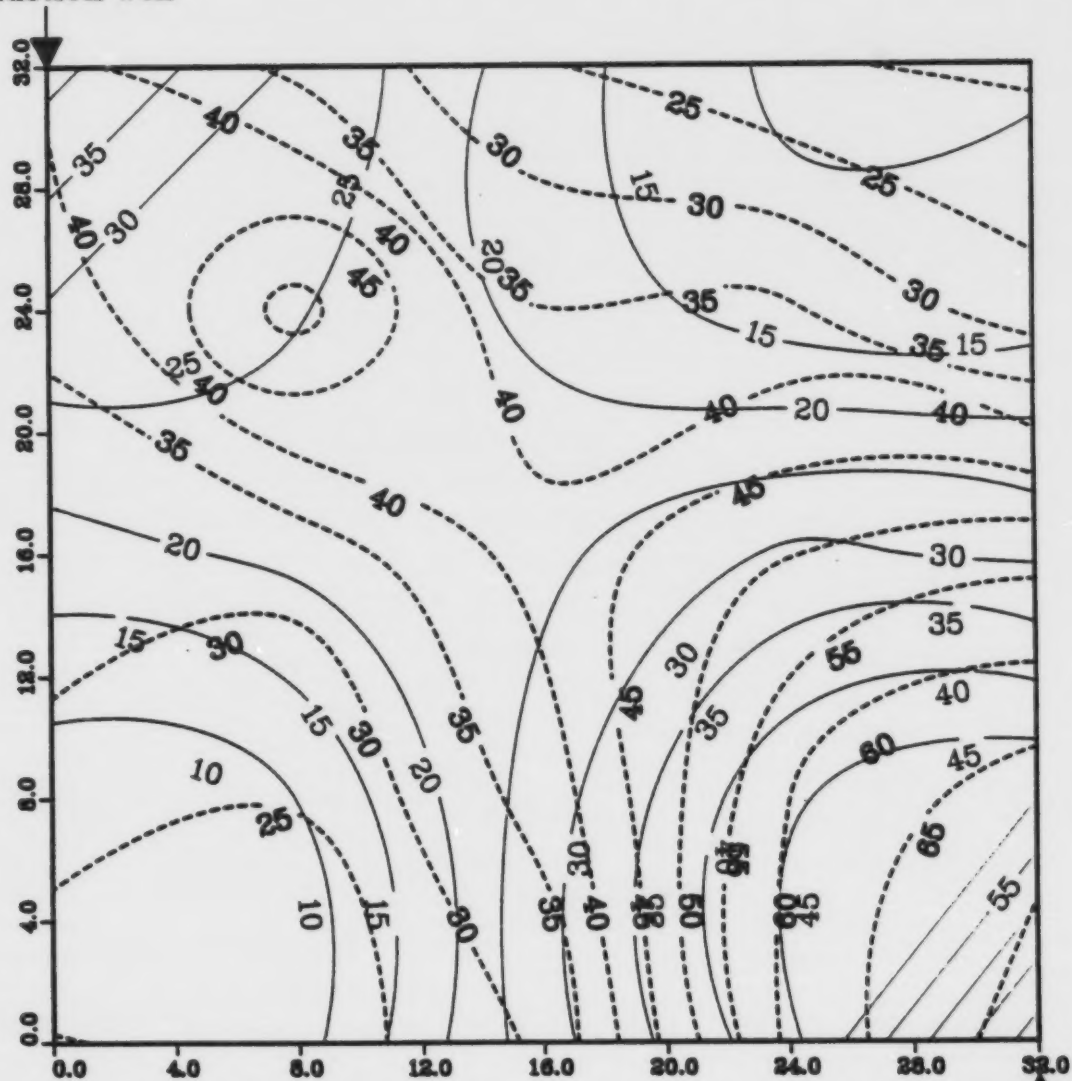


Figure A.75 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



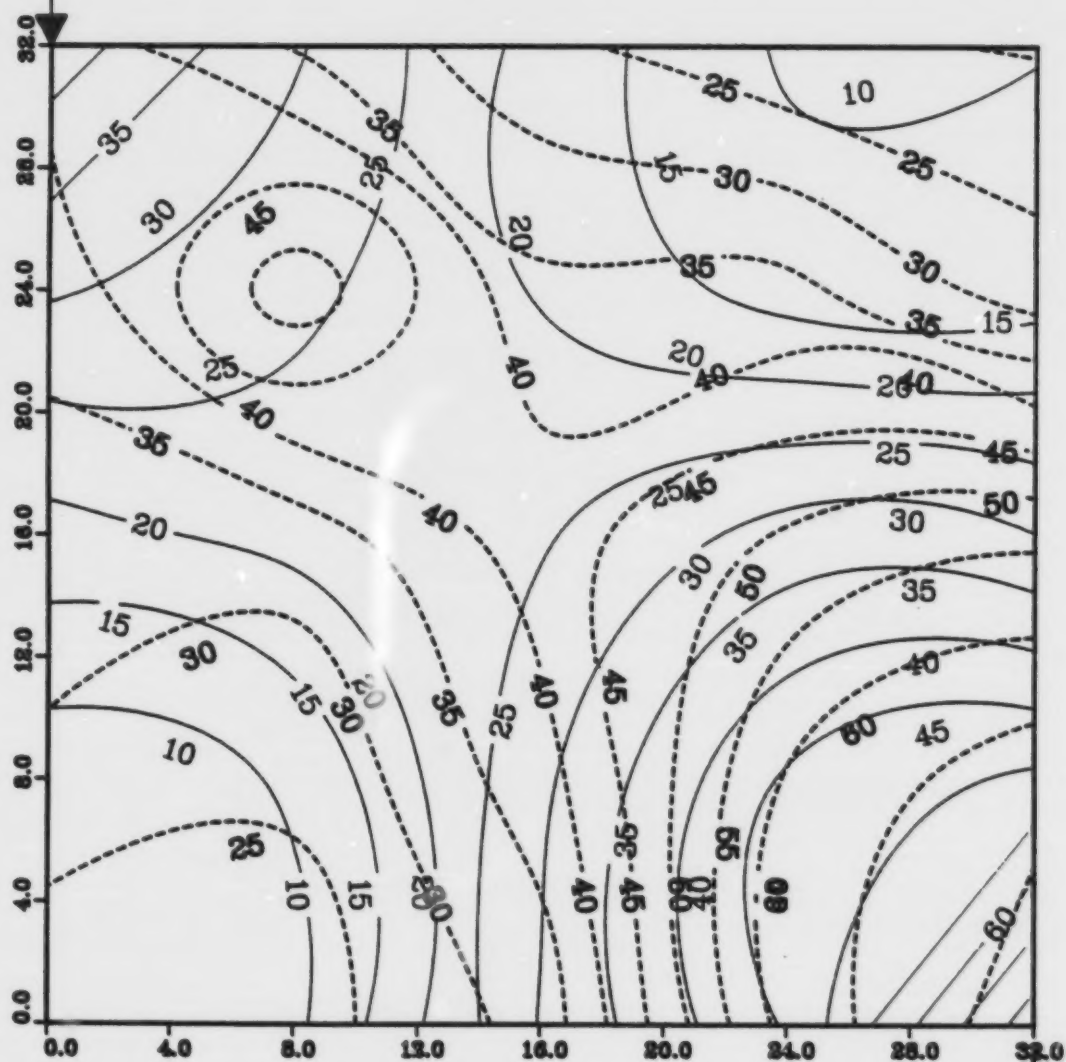
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.76 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

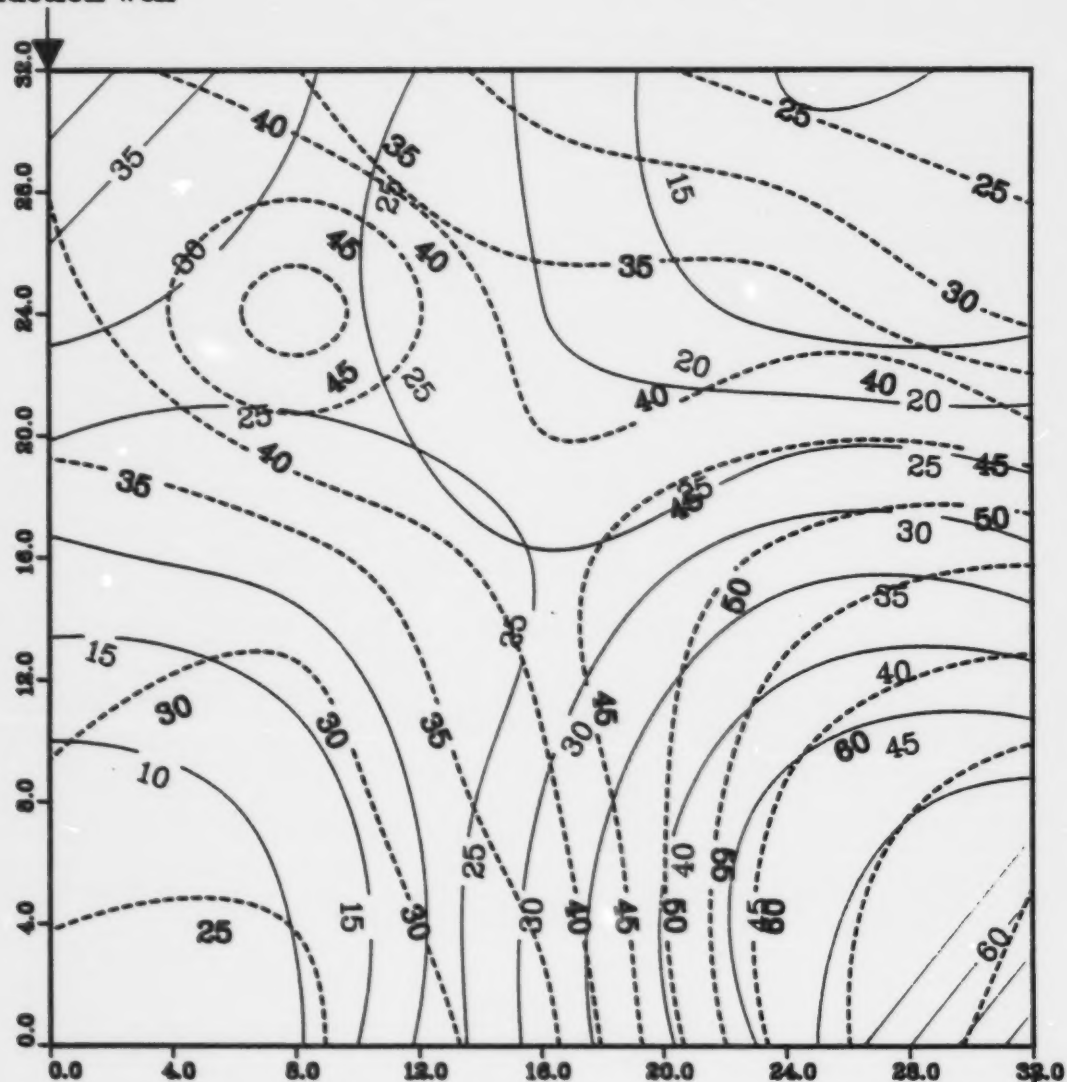
Lower Model Temperature (C)

Injection Well

Figure A.77 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.78 : Run 61
Gas Inj. & Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

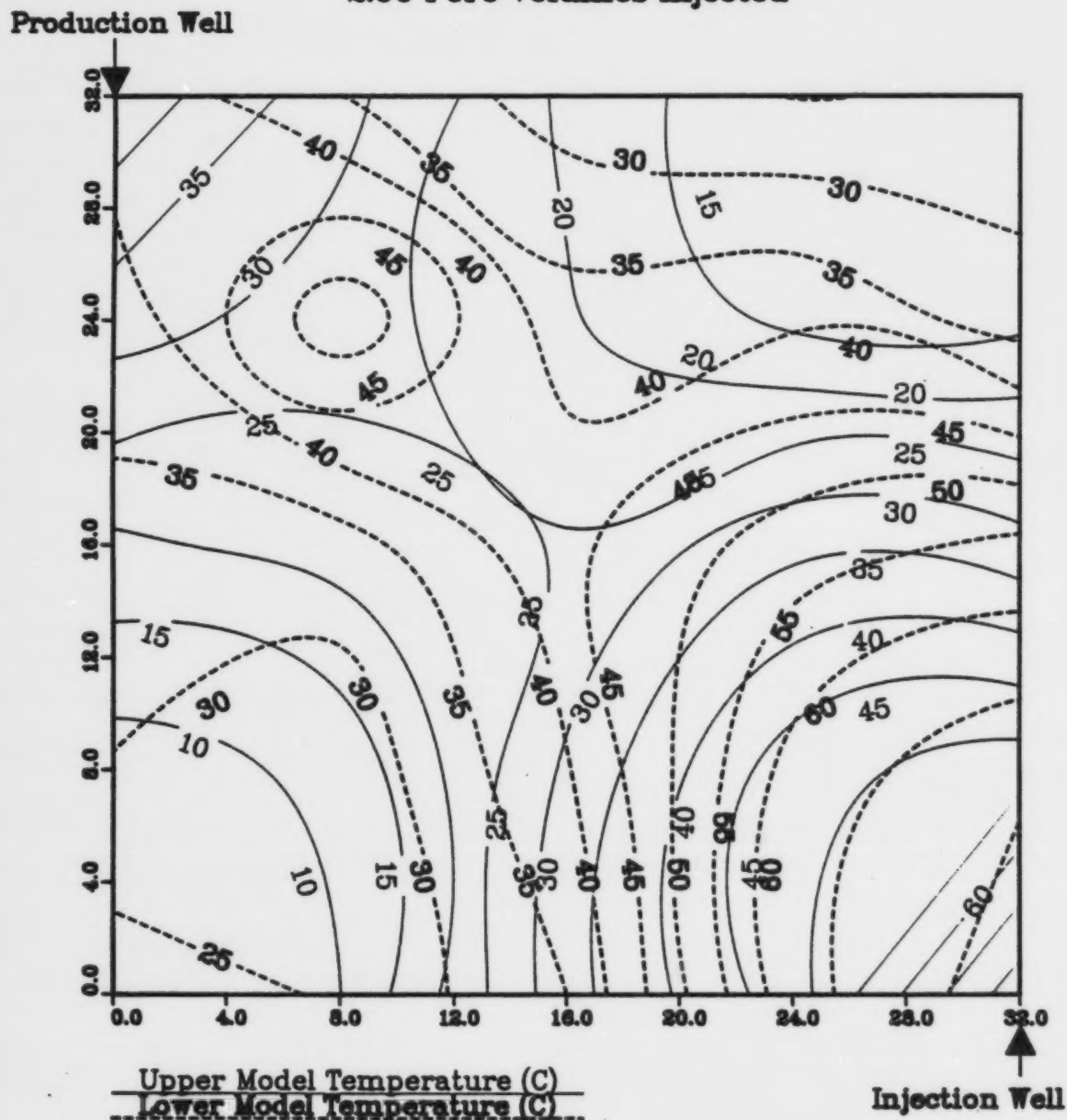


**Figure A.79 :Run 61 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

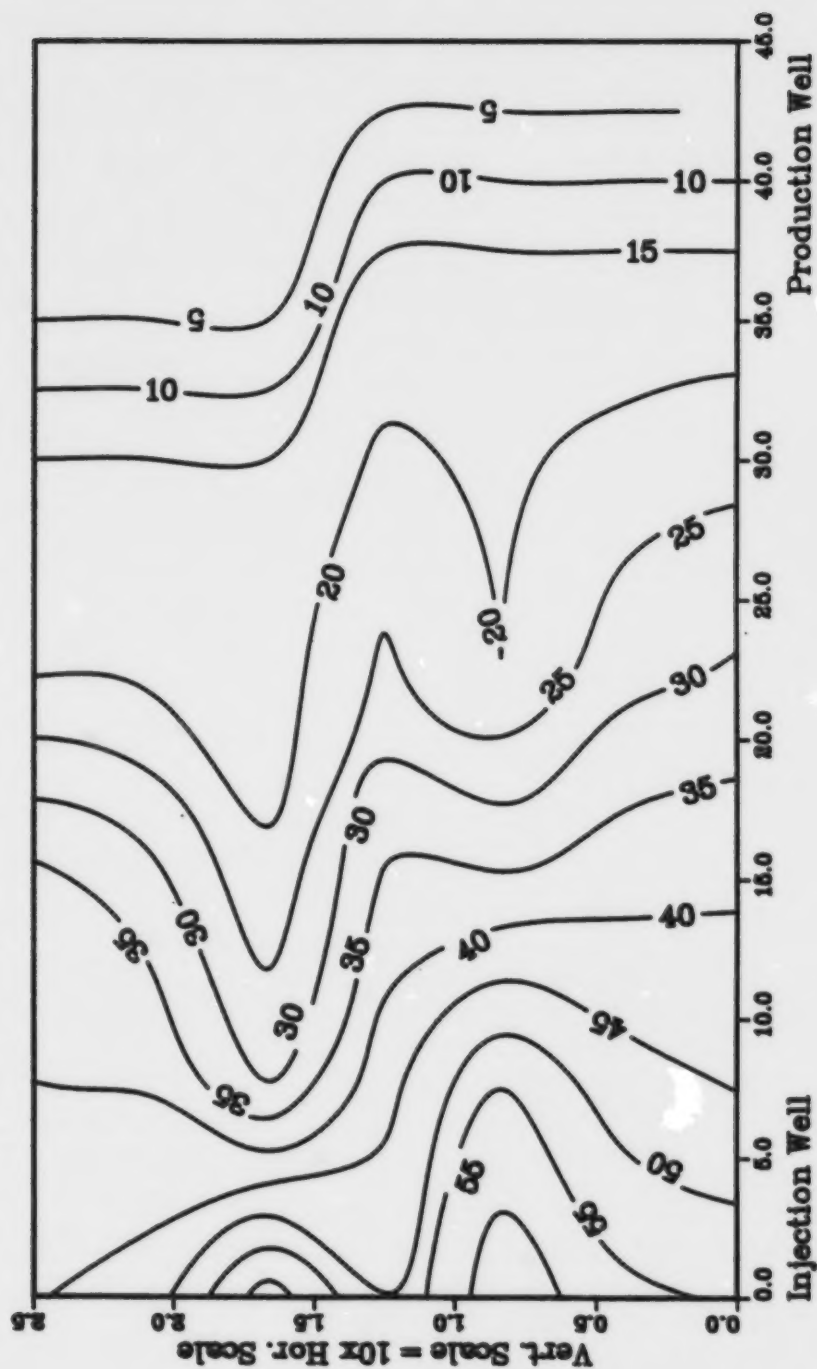


**Figure A.80 :Run 61 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

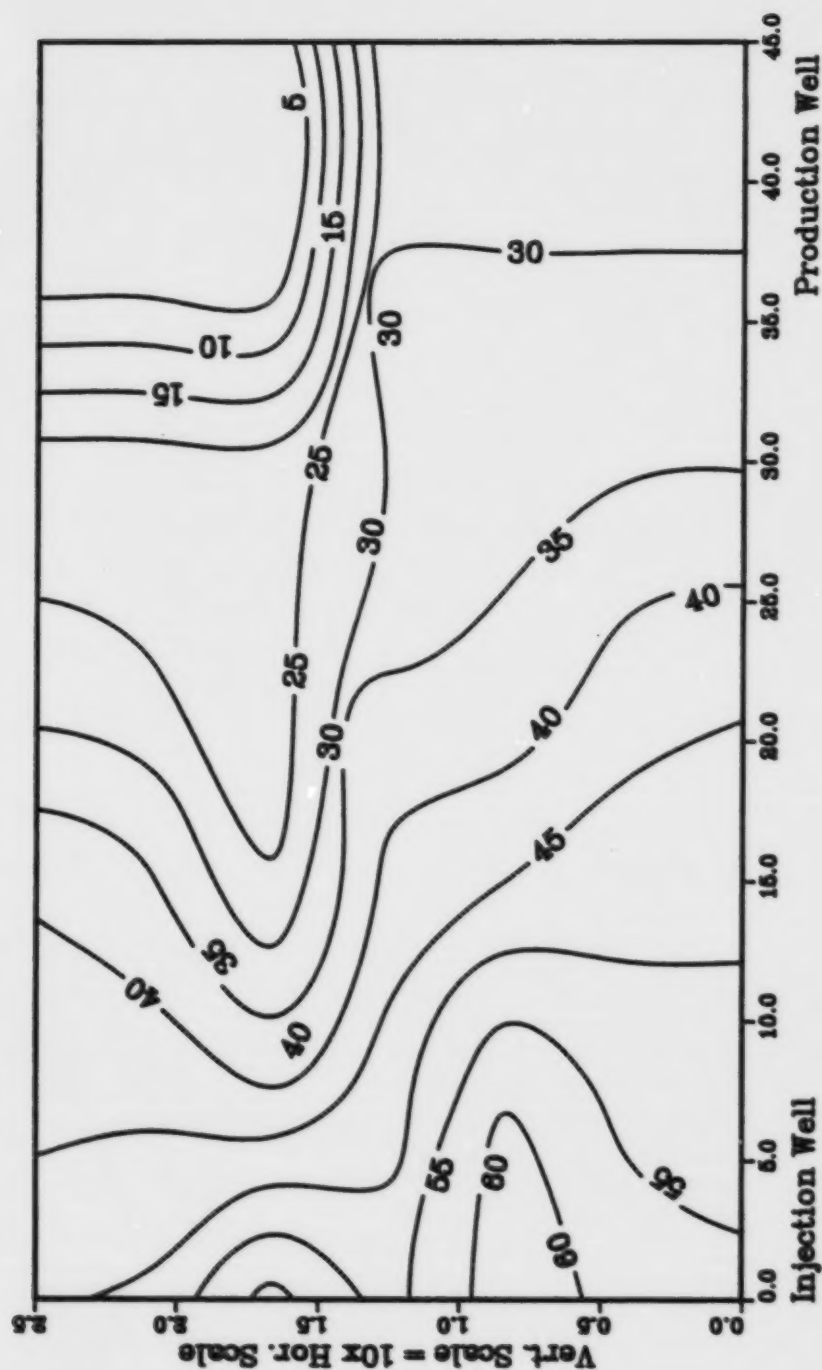


**Figure A.81 :Run 61 Temp Profile
Injector to Producer Cross-Section
0.76 Pore Volumes Injected.**

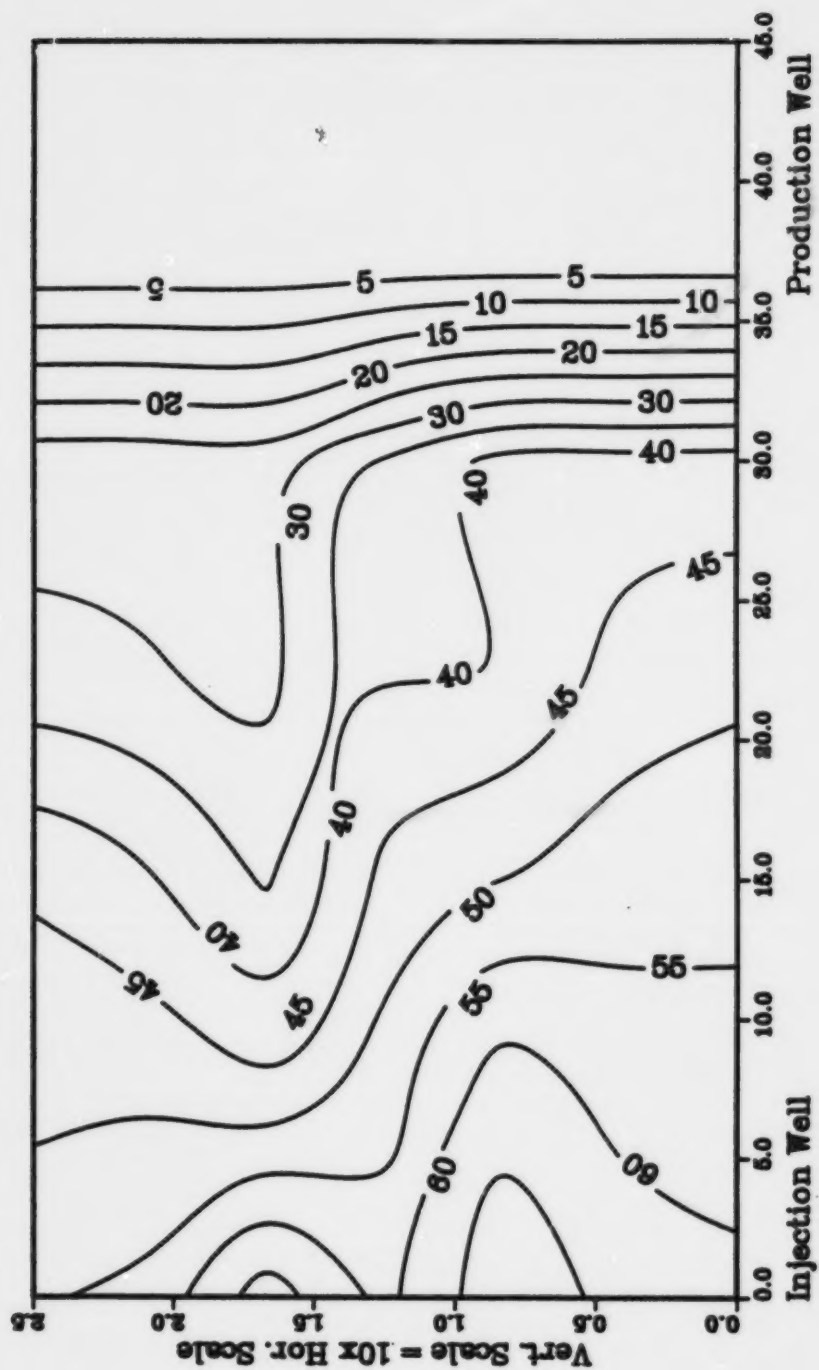


**Figure A.82 :Run 61 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

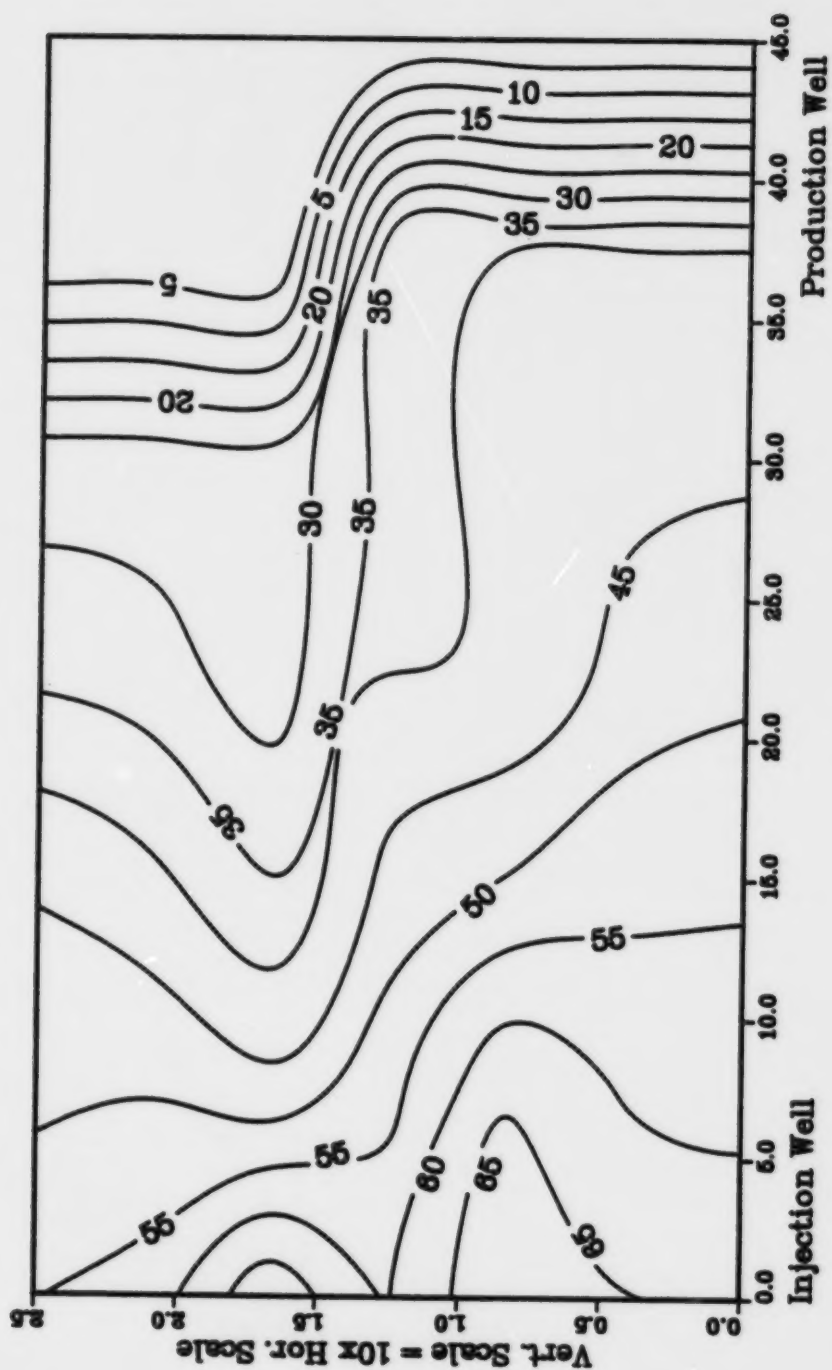


Figure A.83 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

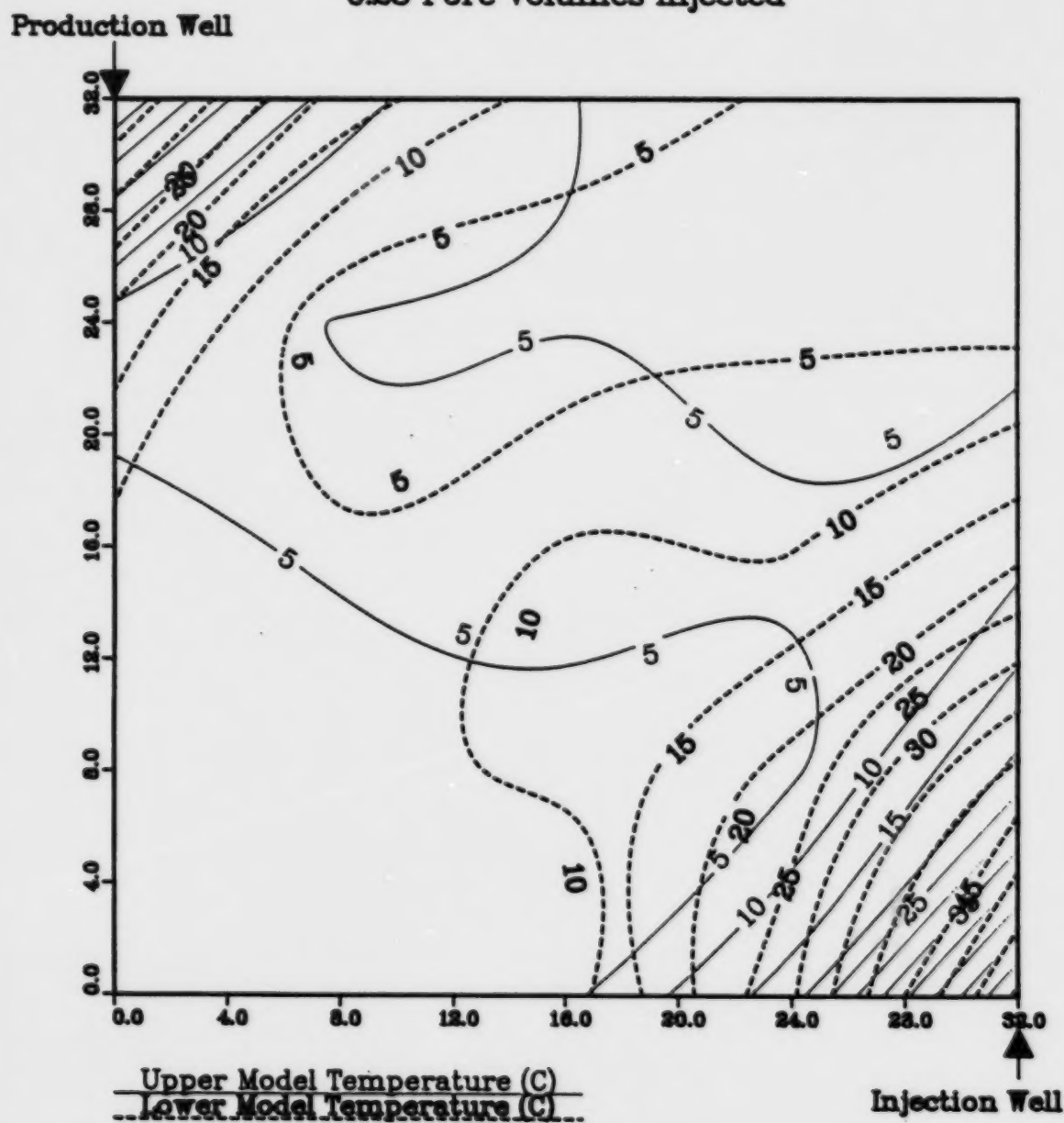


Figure A84 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

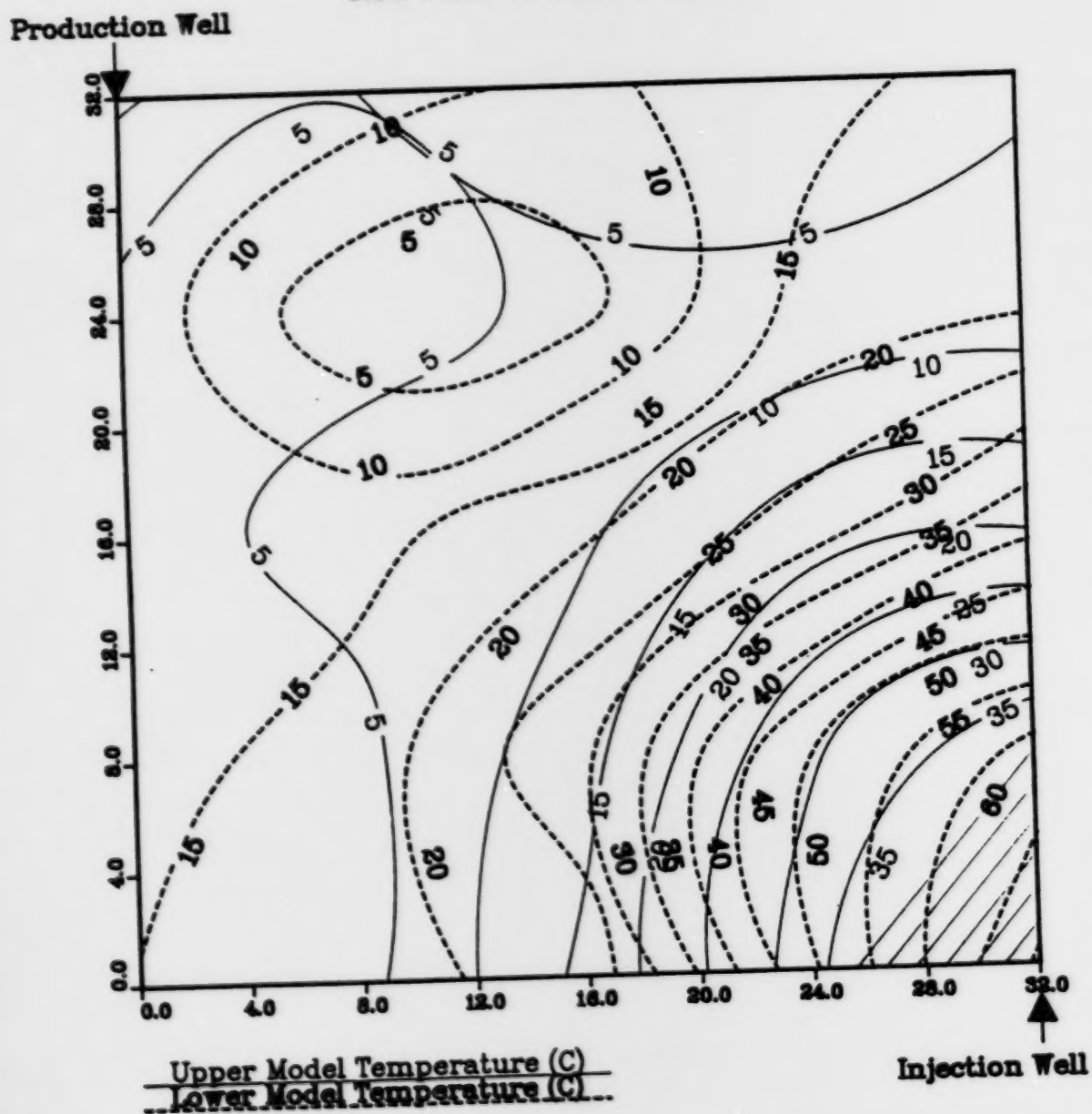
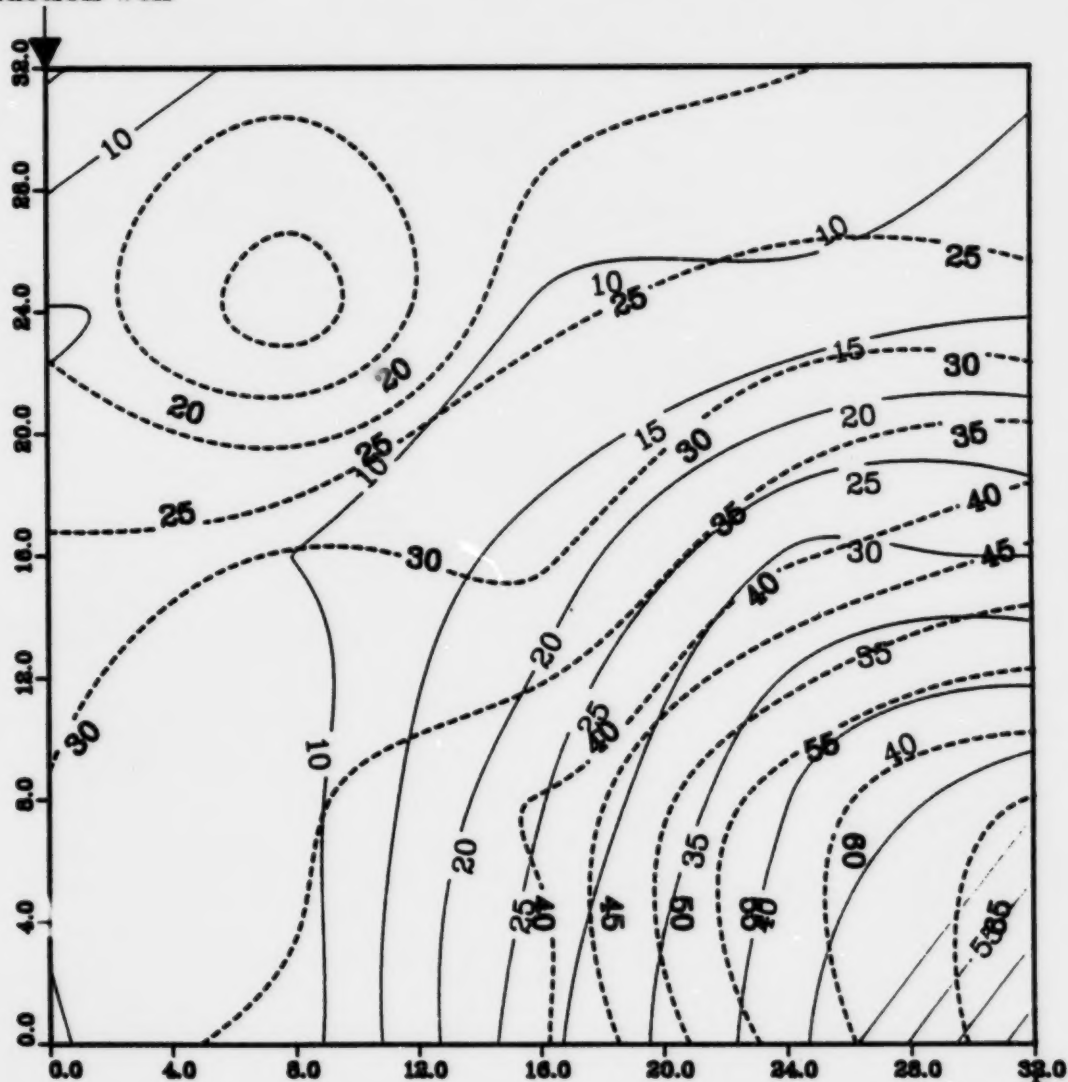


Figure A.85 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.86 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

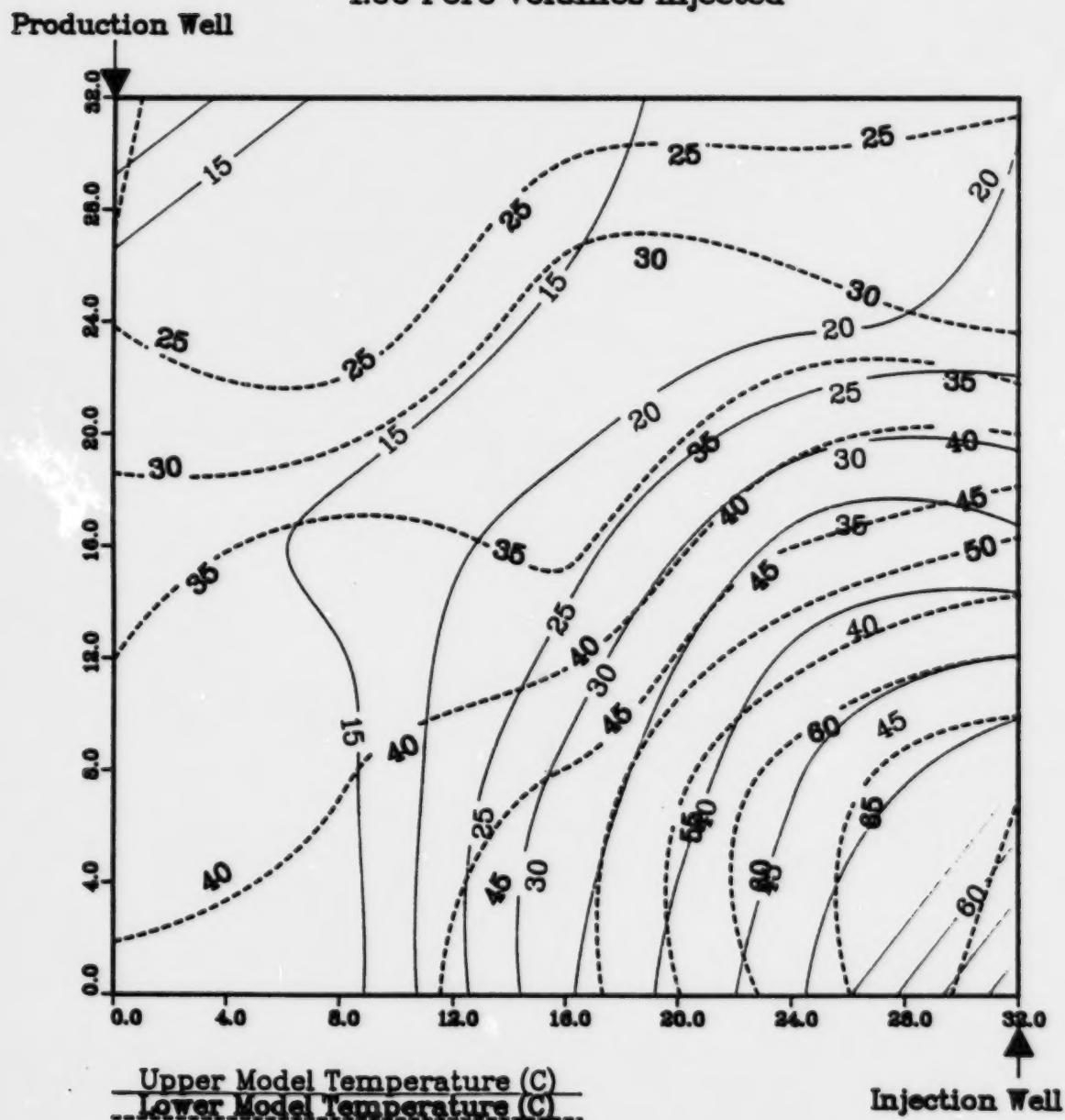
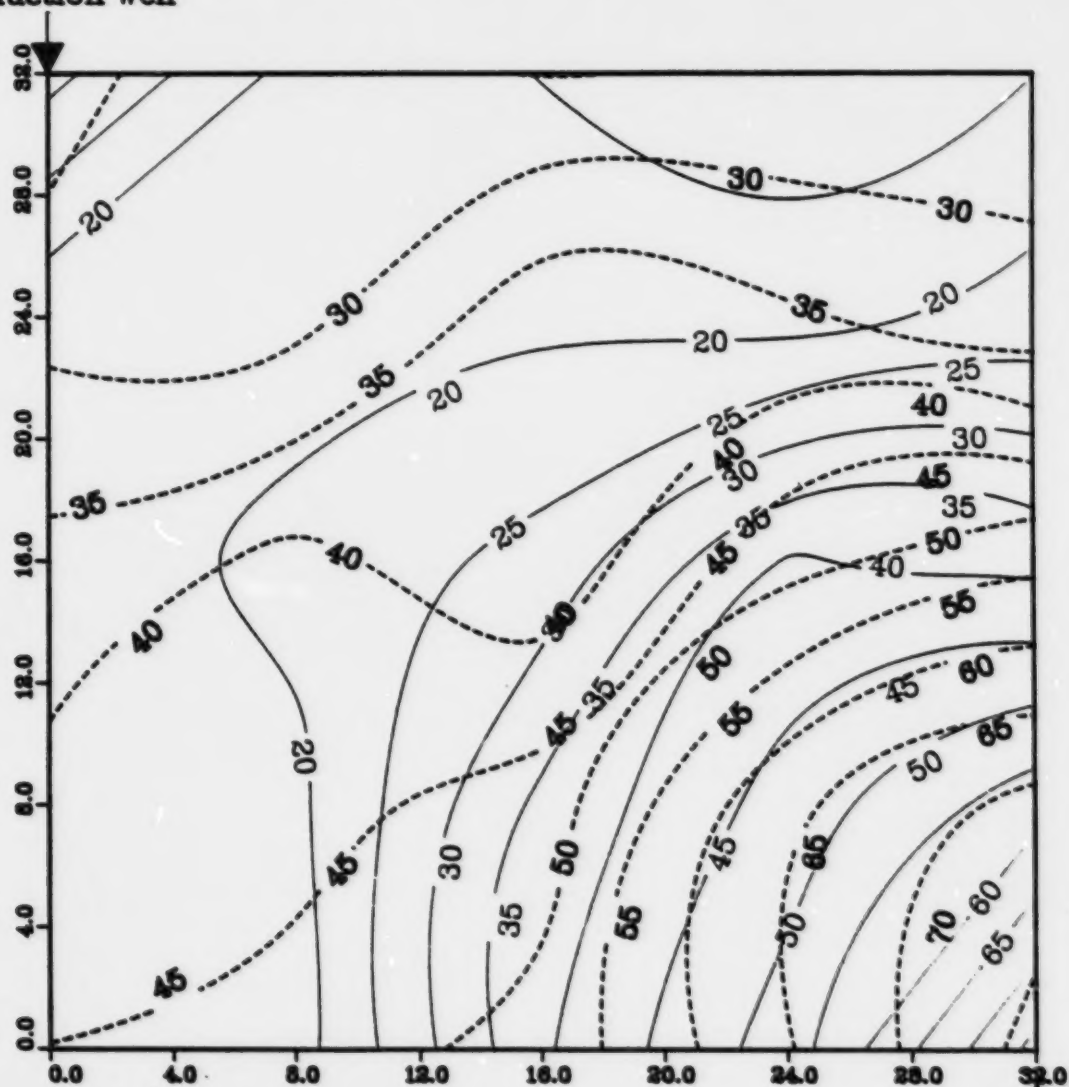


Figure A.87 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

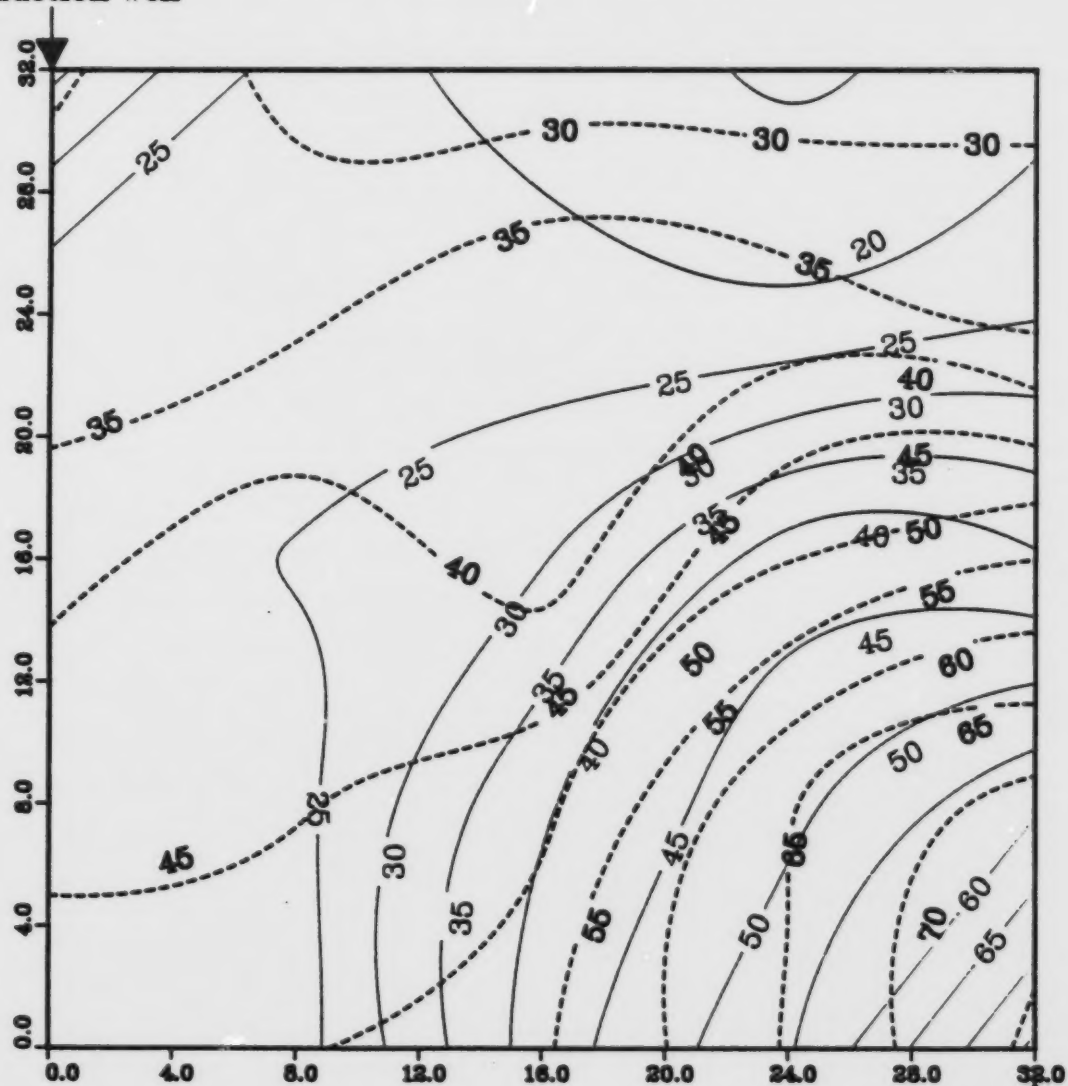
Lower Model Temperature (C)

Injection Well

Figure A.88 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

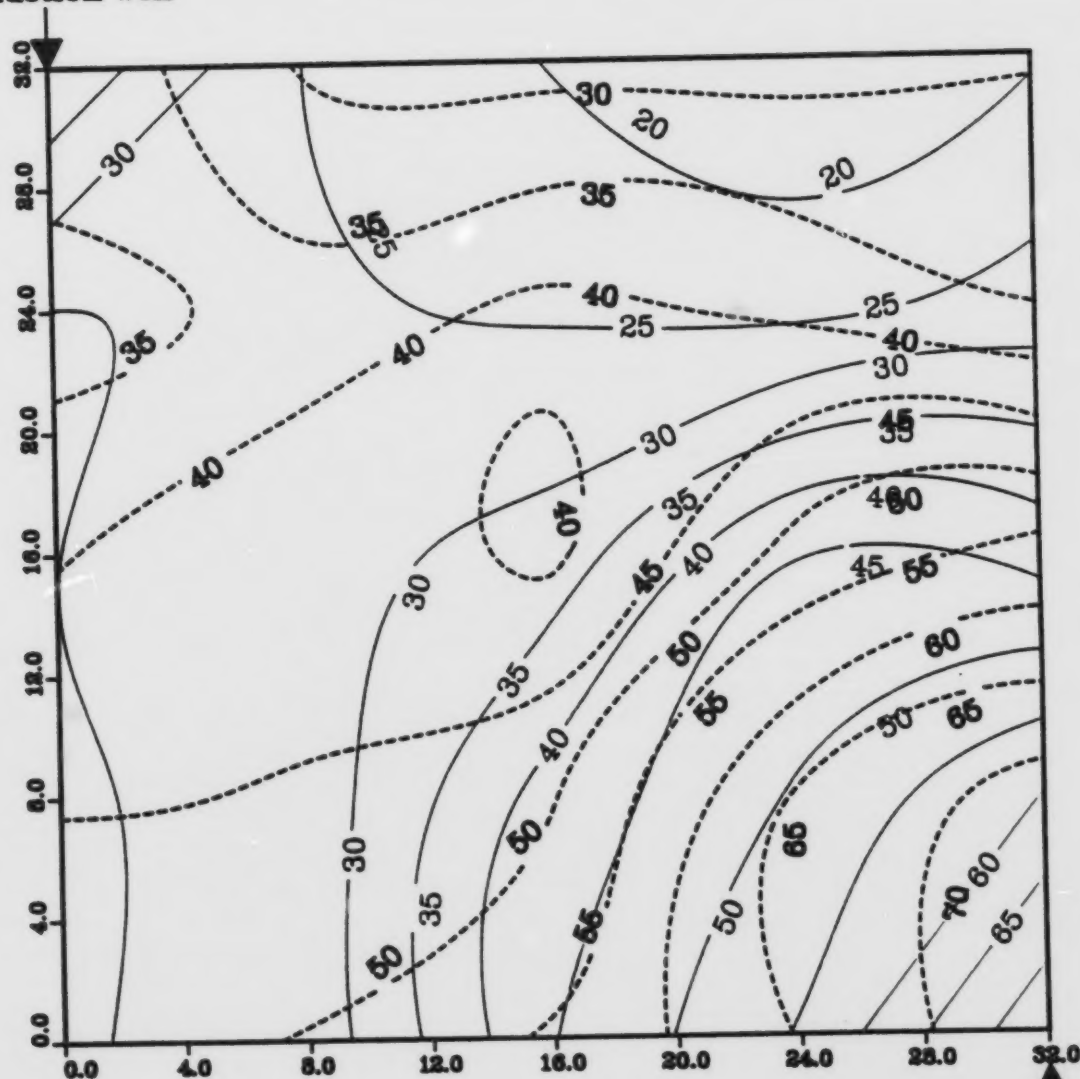
Lower Model Temperature (C)

Injection Well

Figure A.89 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.90 : Run 65
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

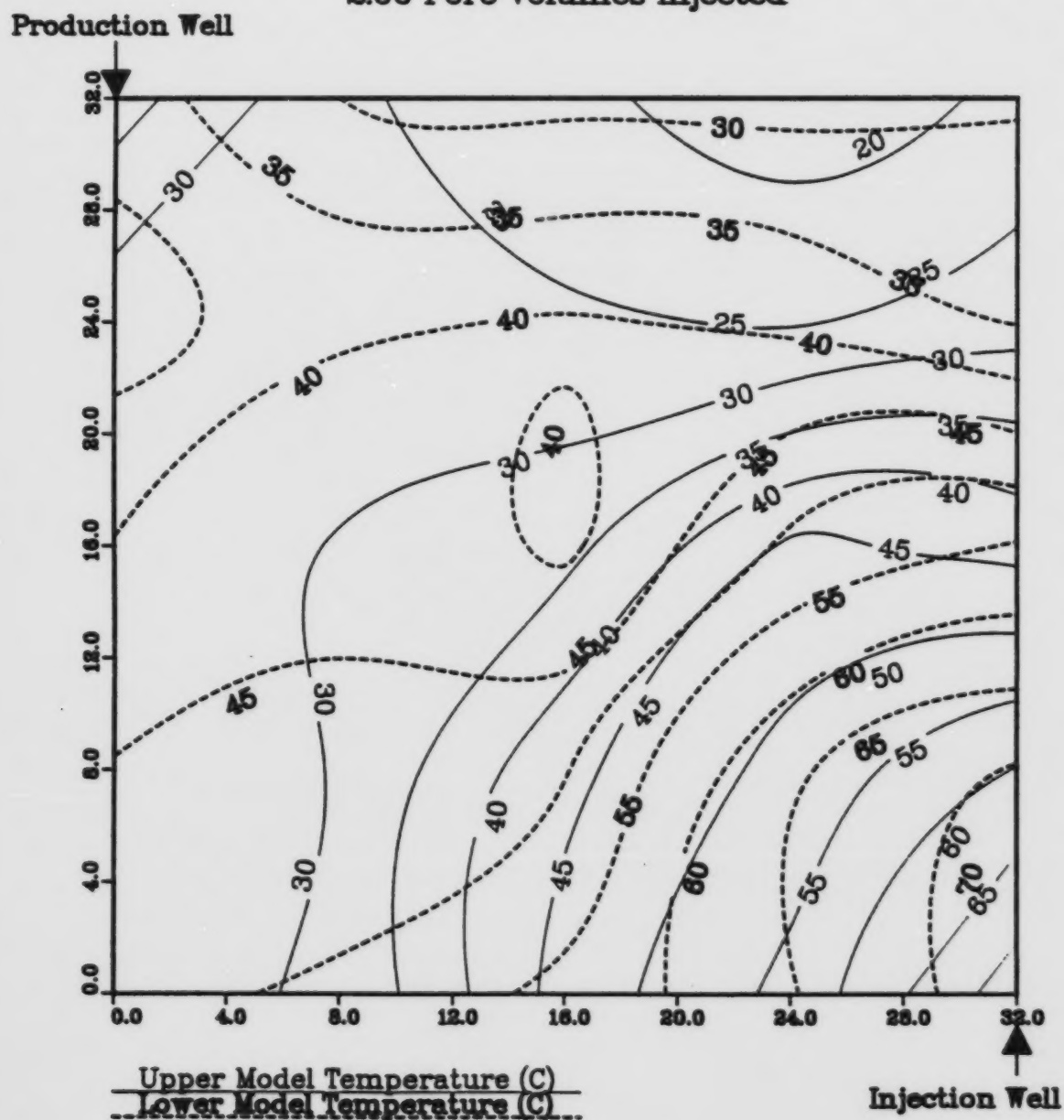


**Figure A.91 :Run 65 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

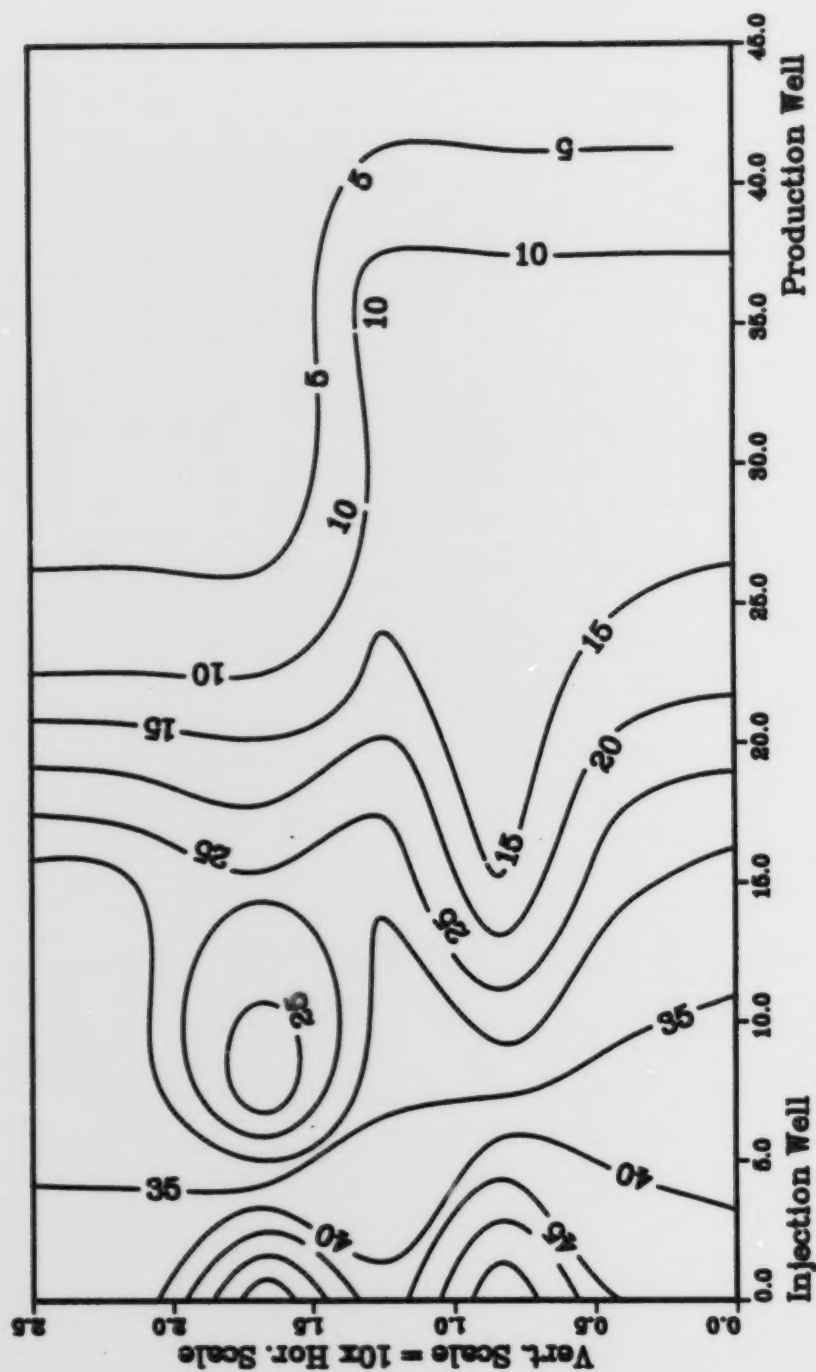


**Figure A.92 :Run 65 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

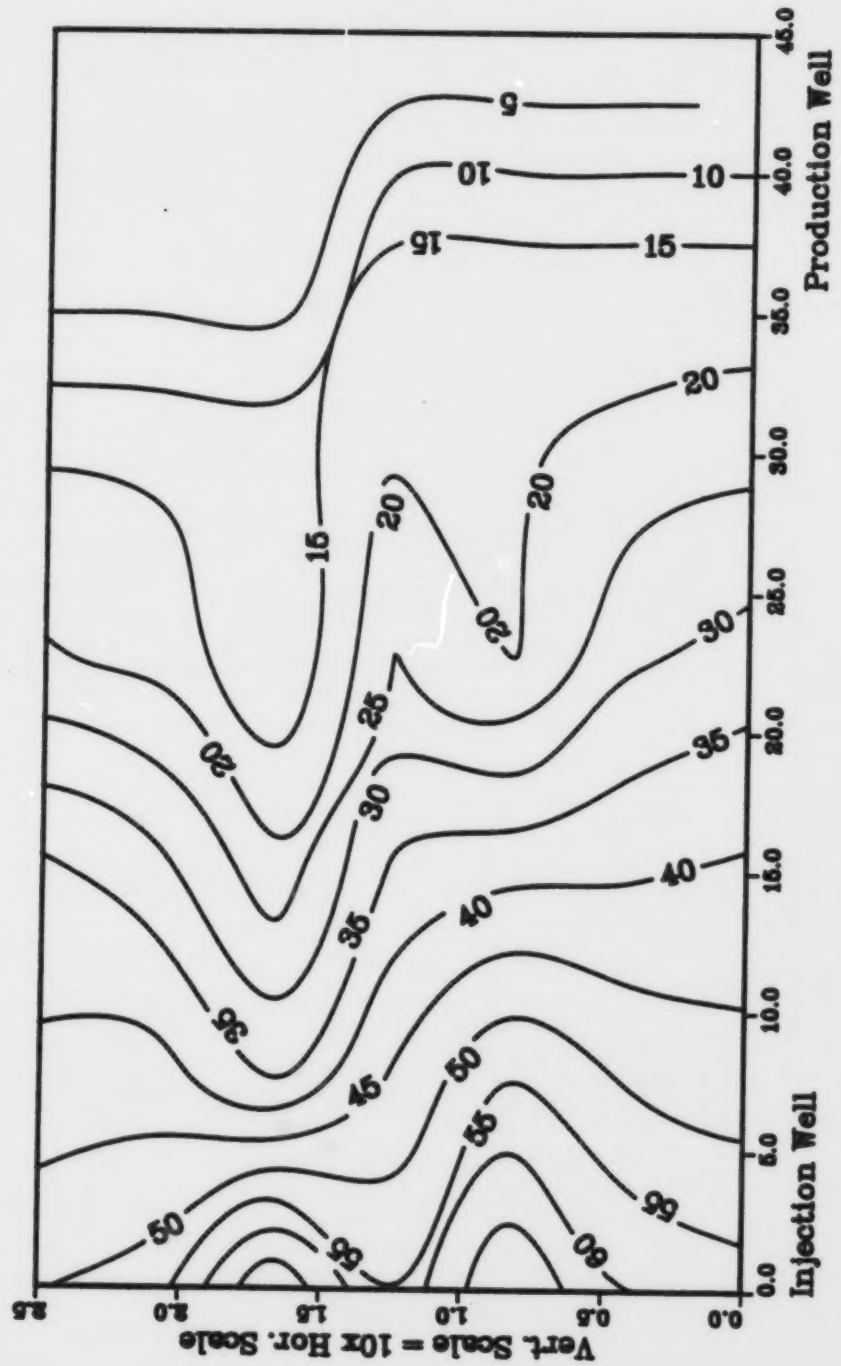


**Figure A.93 :Run 65 Temp Profile
Injector to Producer Cross-Section
0.76 Pore Volumes Injected.**

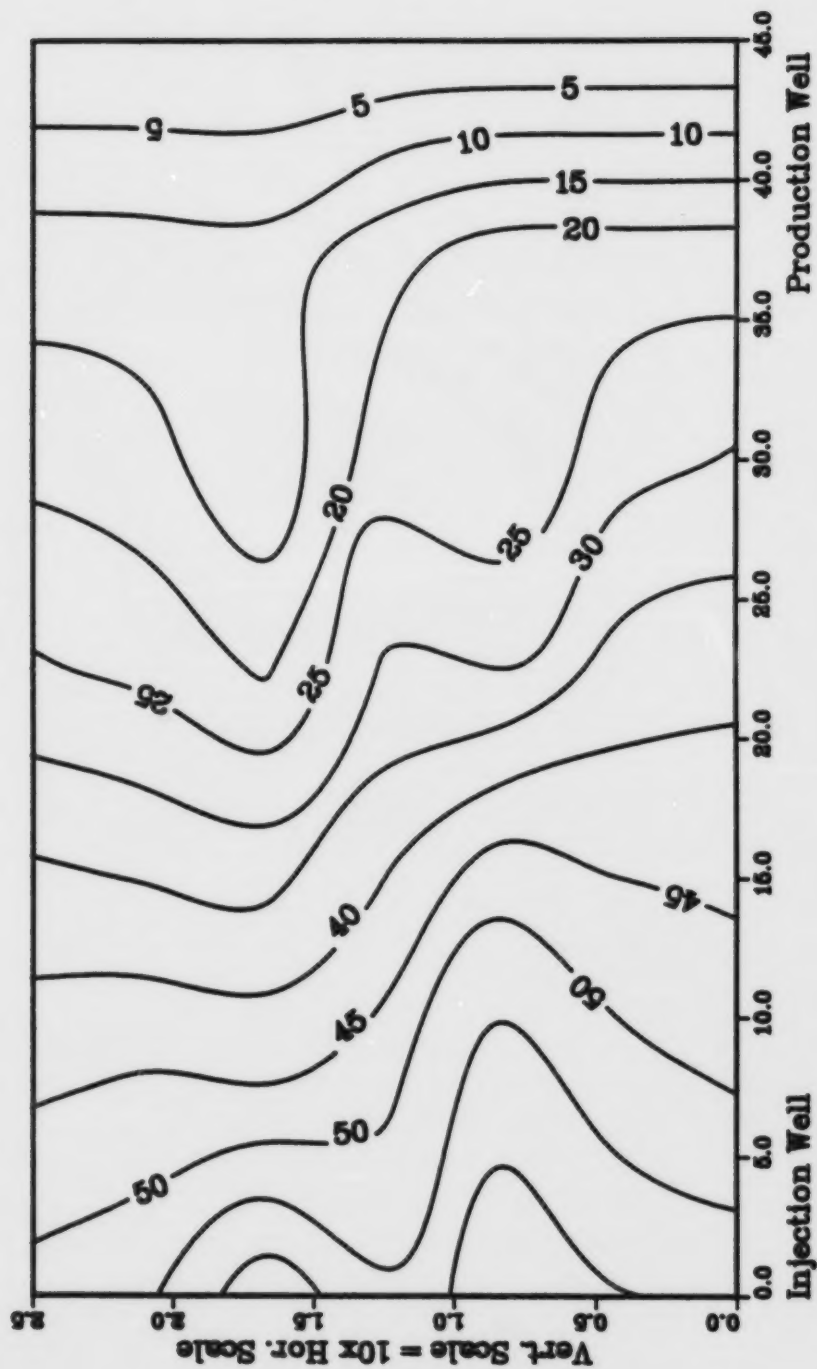


**Figure A.94 :Run 65 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

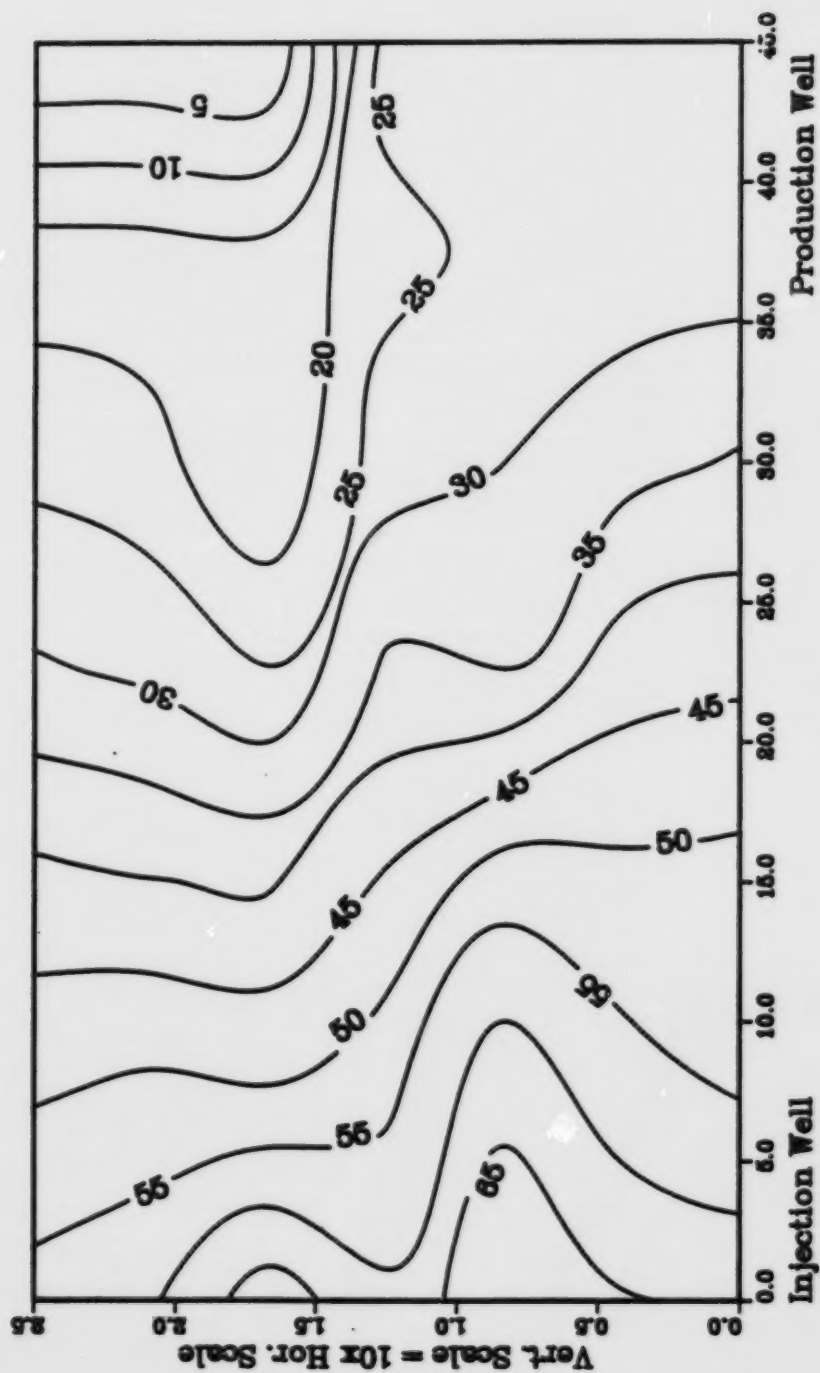


Figure A.95 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.25 Pore Volumes Injected

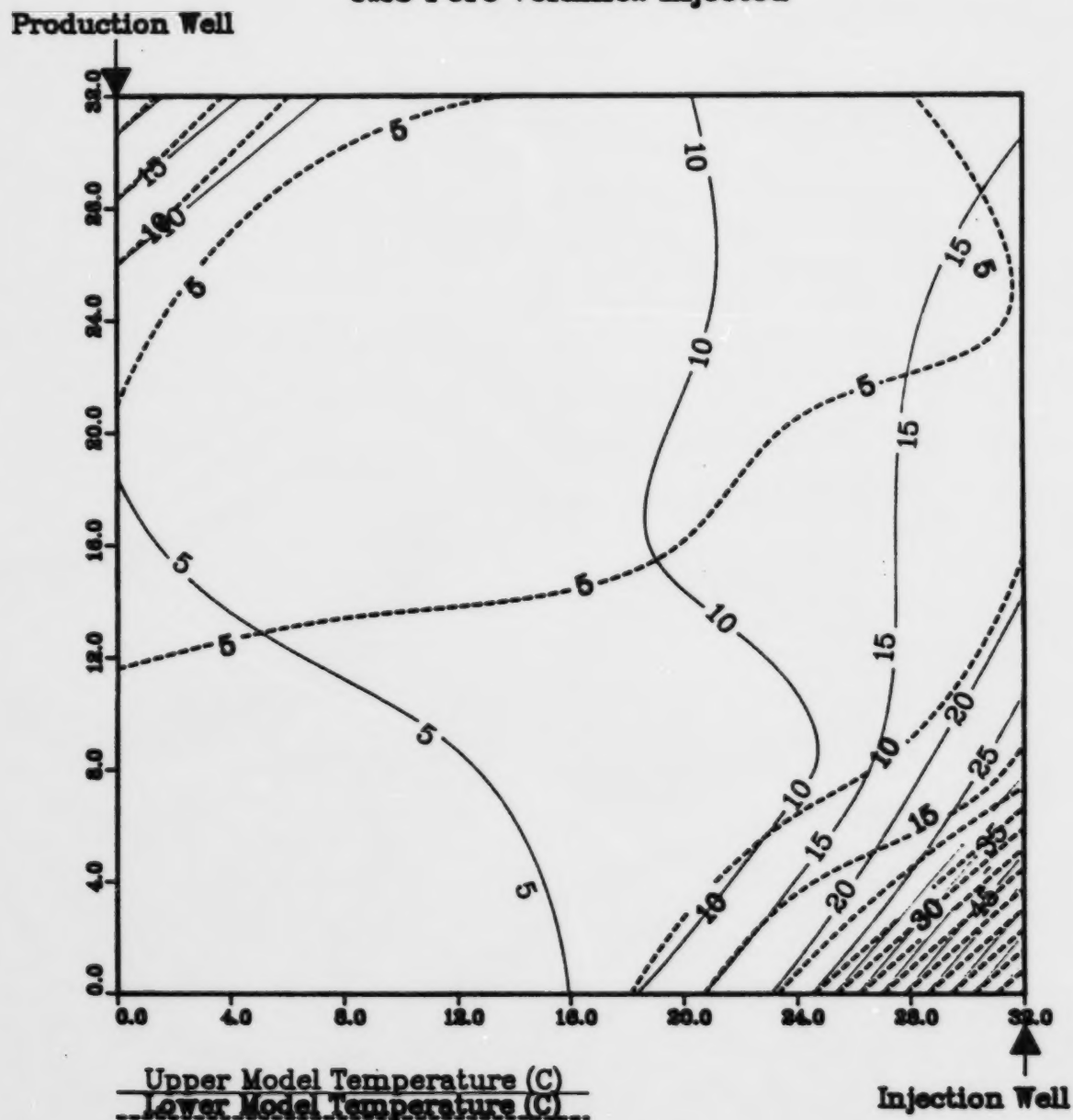
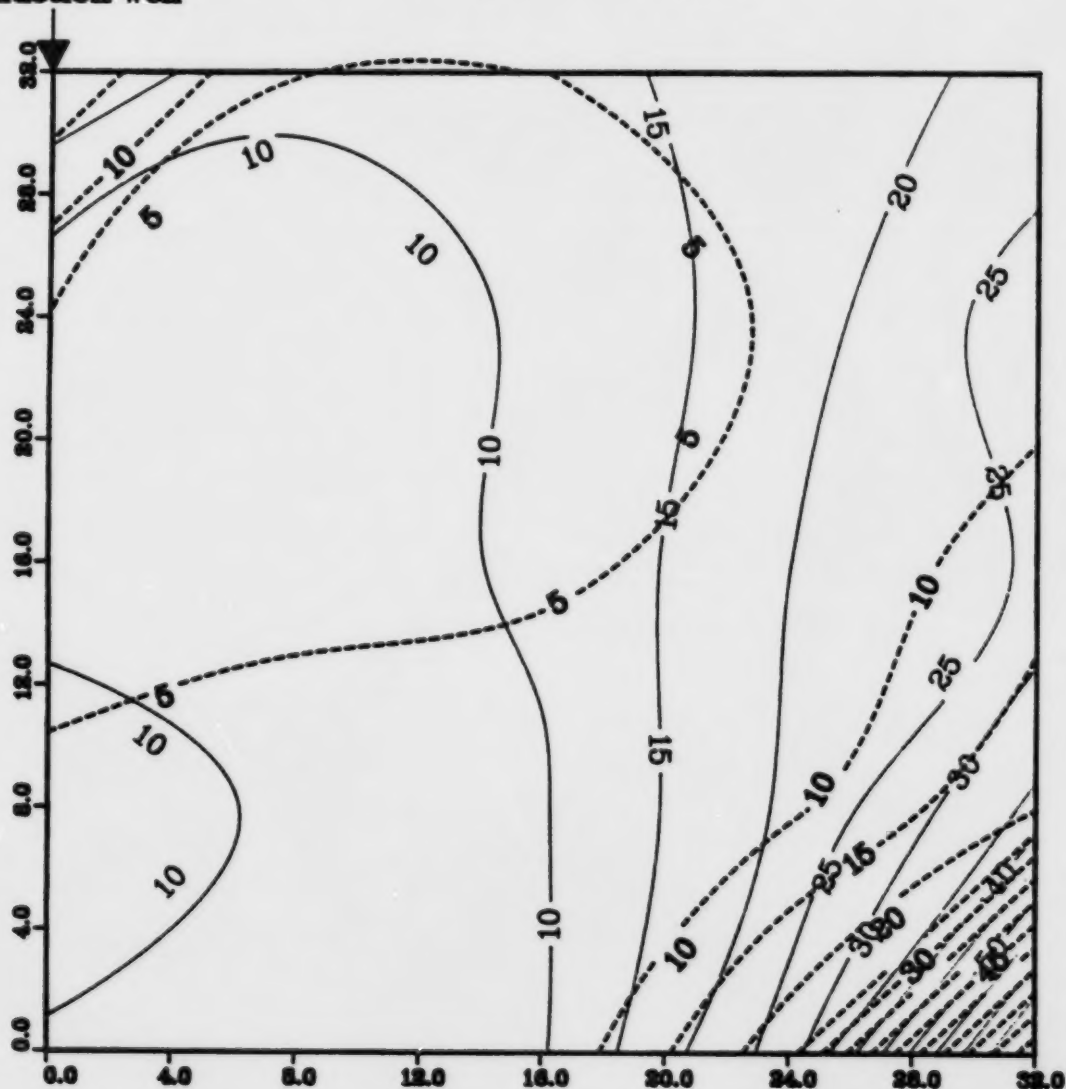


Figure A.96 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



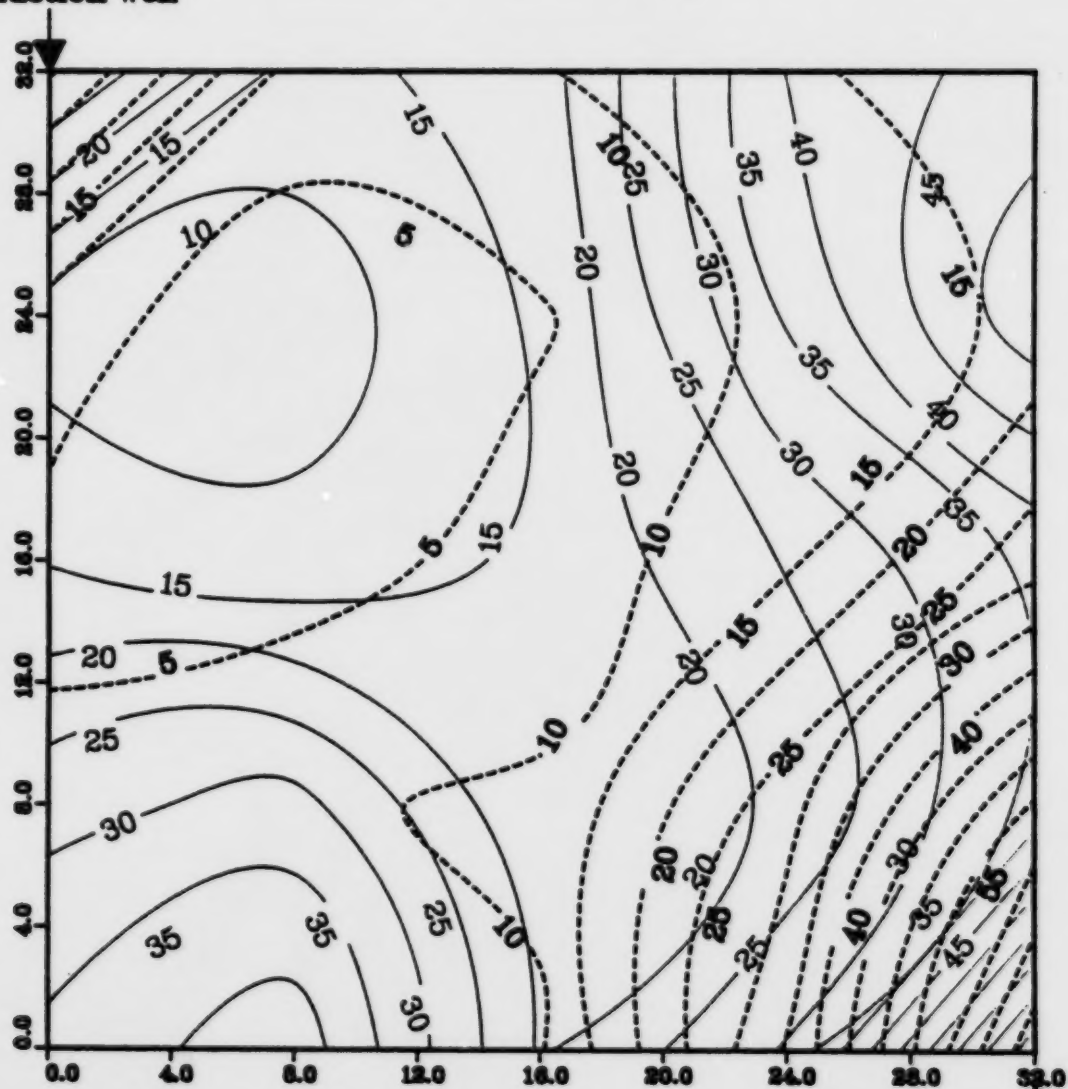
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.97 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.98 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well

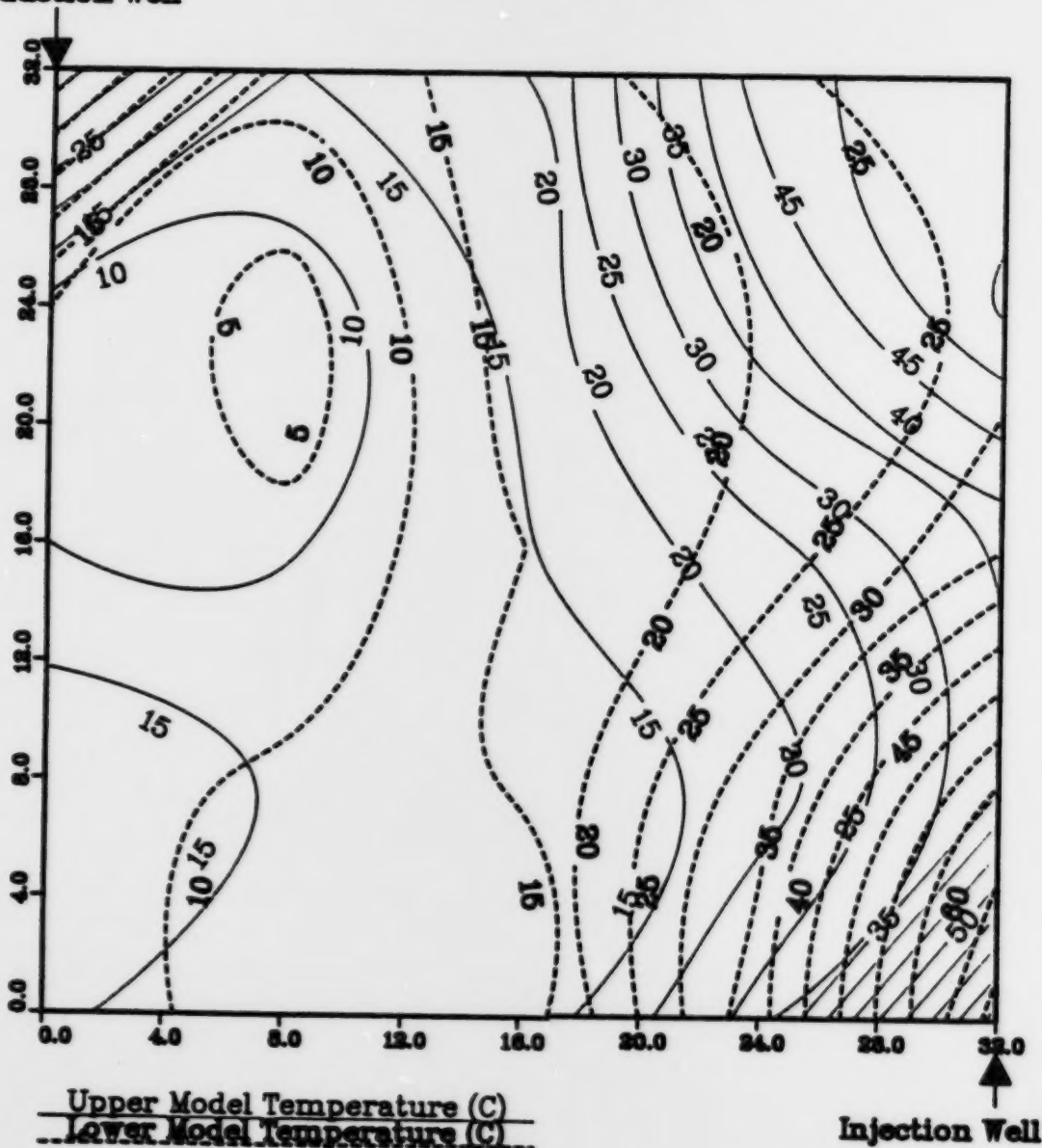


Figure A.99 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.25 Pore Volumes Injected

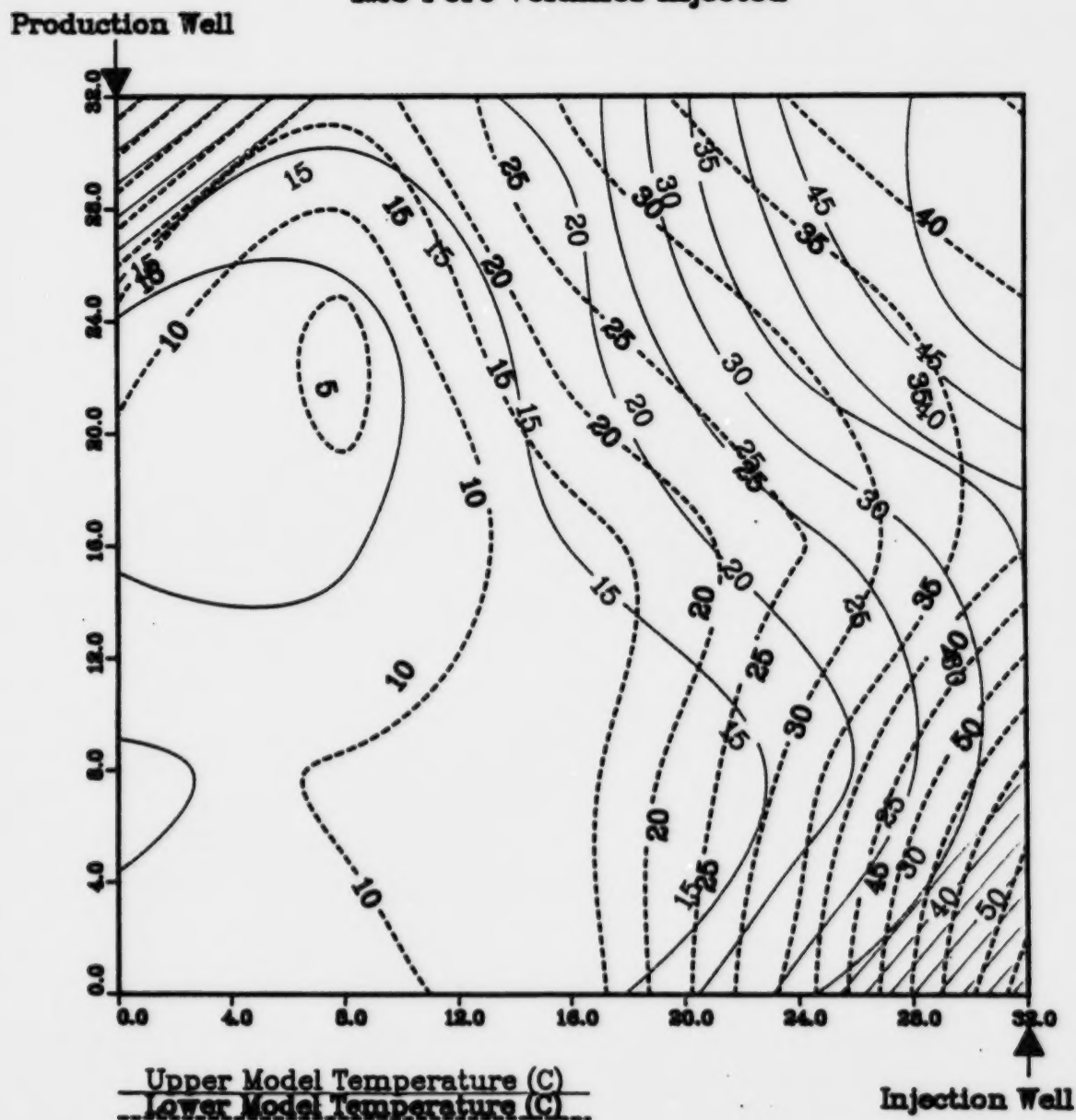


Figure A.100 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.50 Pore Volumes Injected

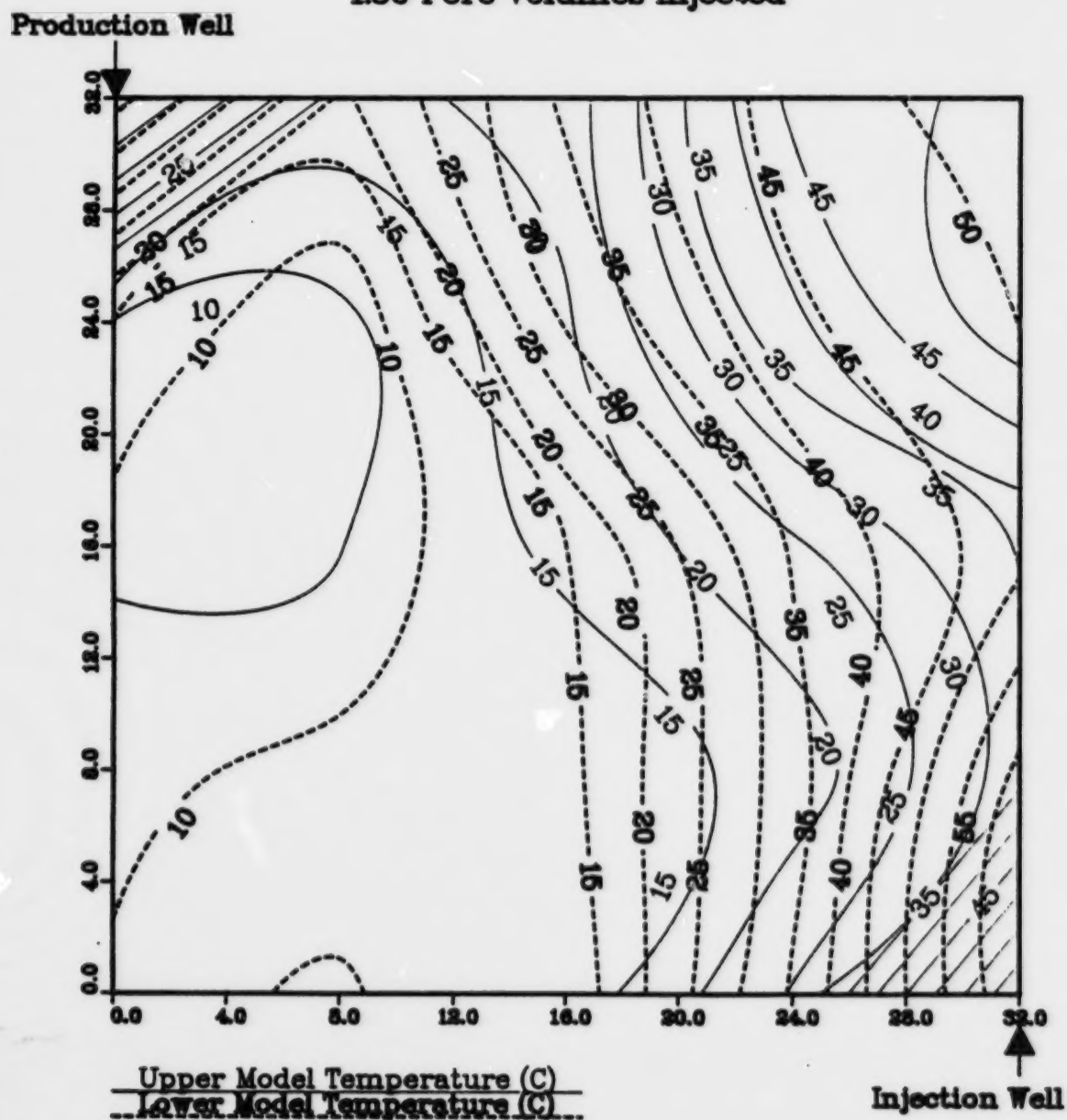


Figure A.101 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.75 Pore Volumes Injected

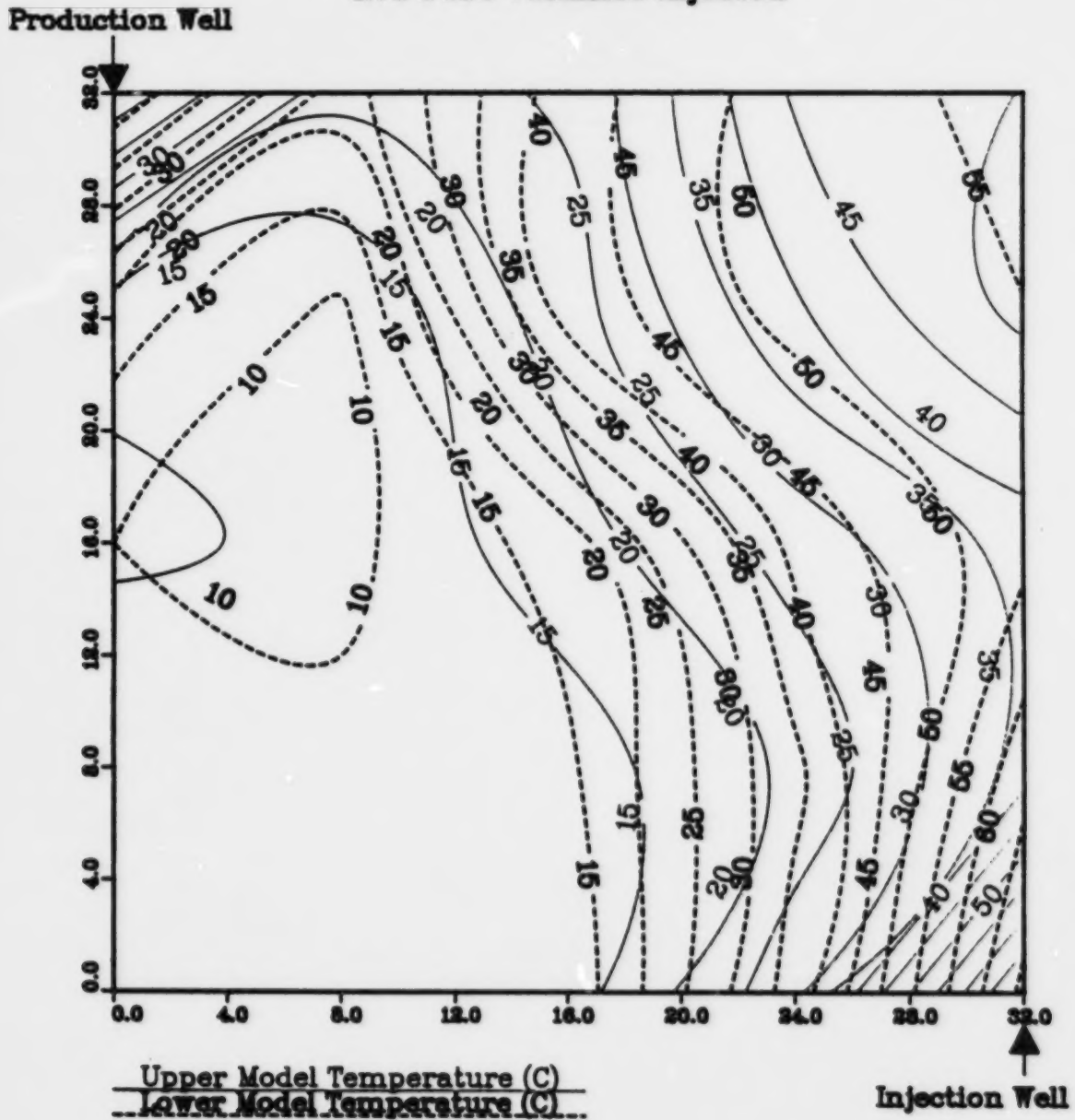


Figure A.102 : Run 66
Solvent-Steamflood in Homo. Model

Temperature Profile for
2.00 Pore Volumes Injected

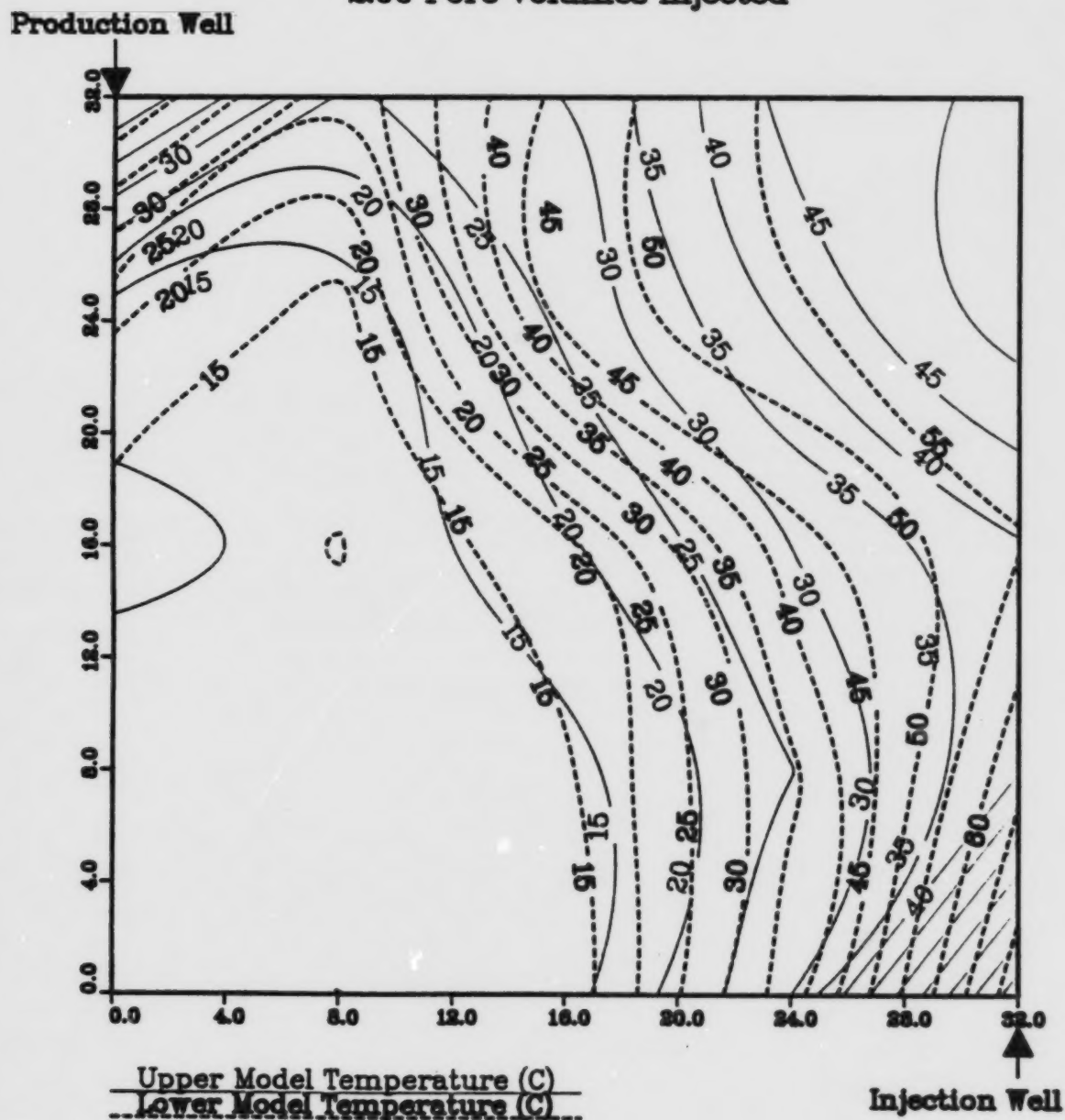


**Figure A.103 :Run 66 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

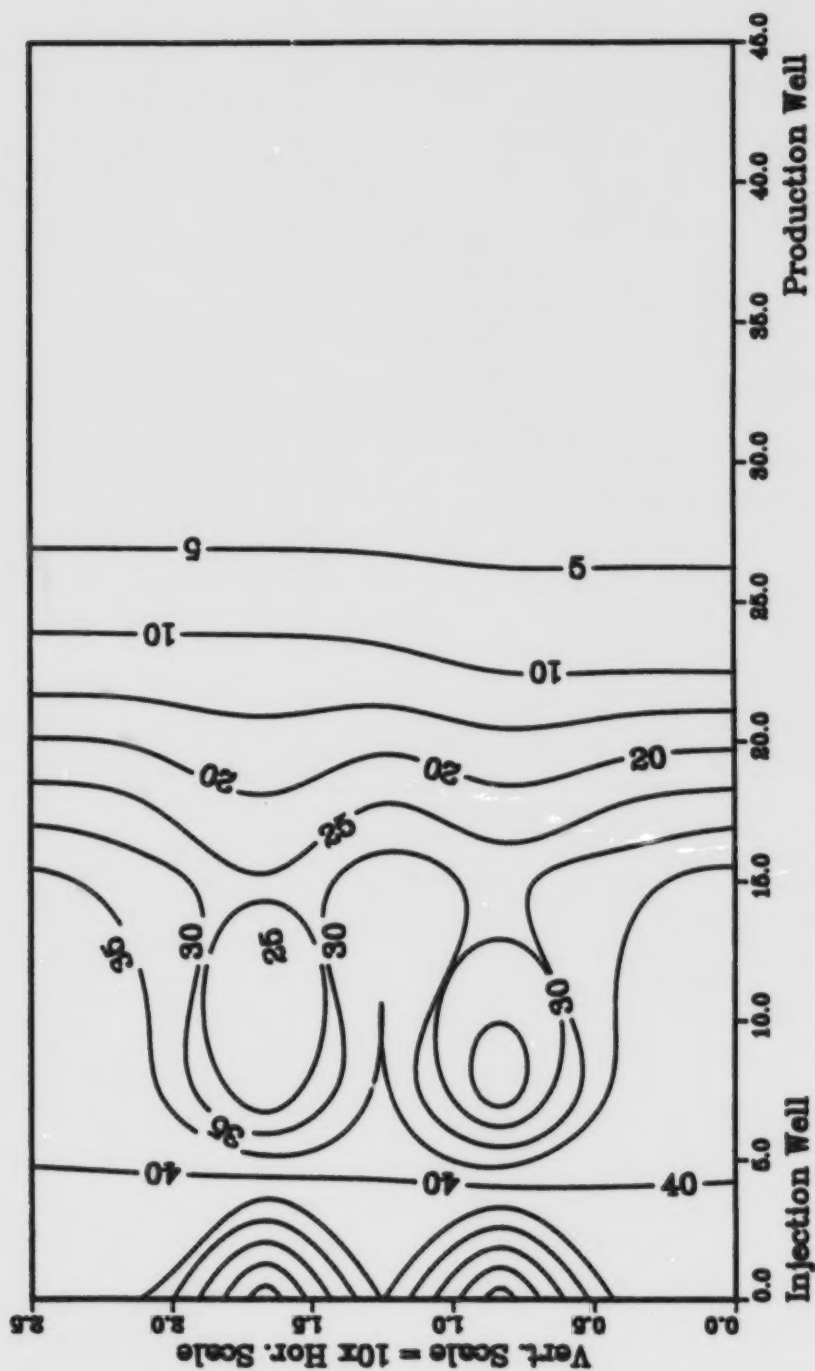


**Figure A.104 :Run 66 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

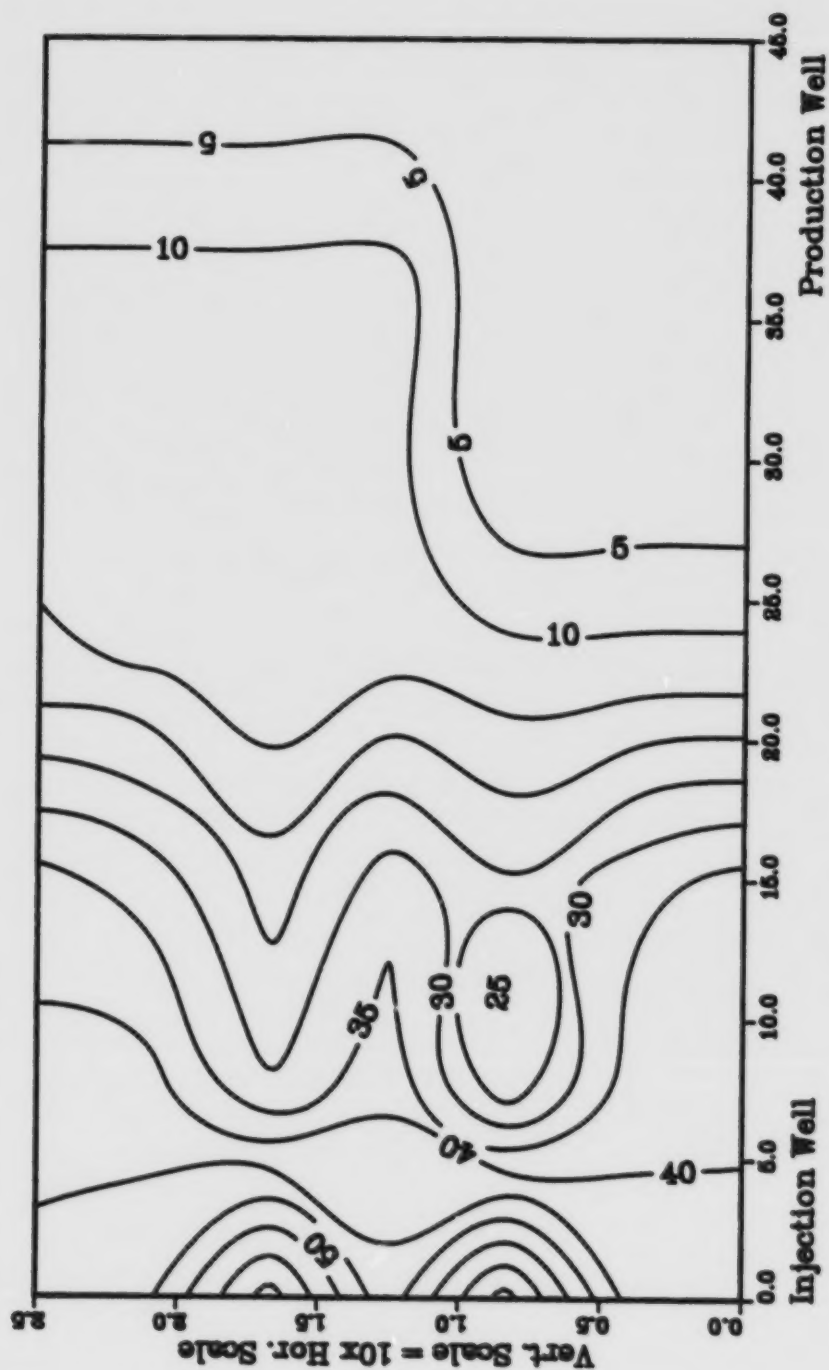


**Figure A.105 :Run 66 Temp Profile
Injector to Producer Cross-Section**
0.76 Pore Volumes Injected.

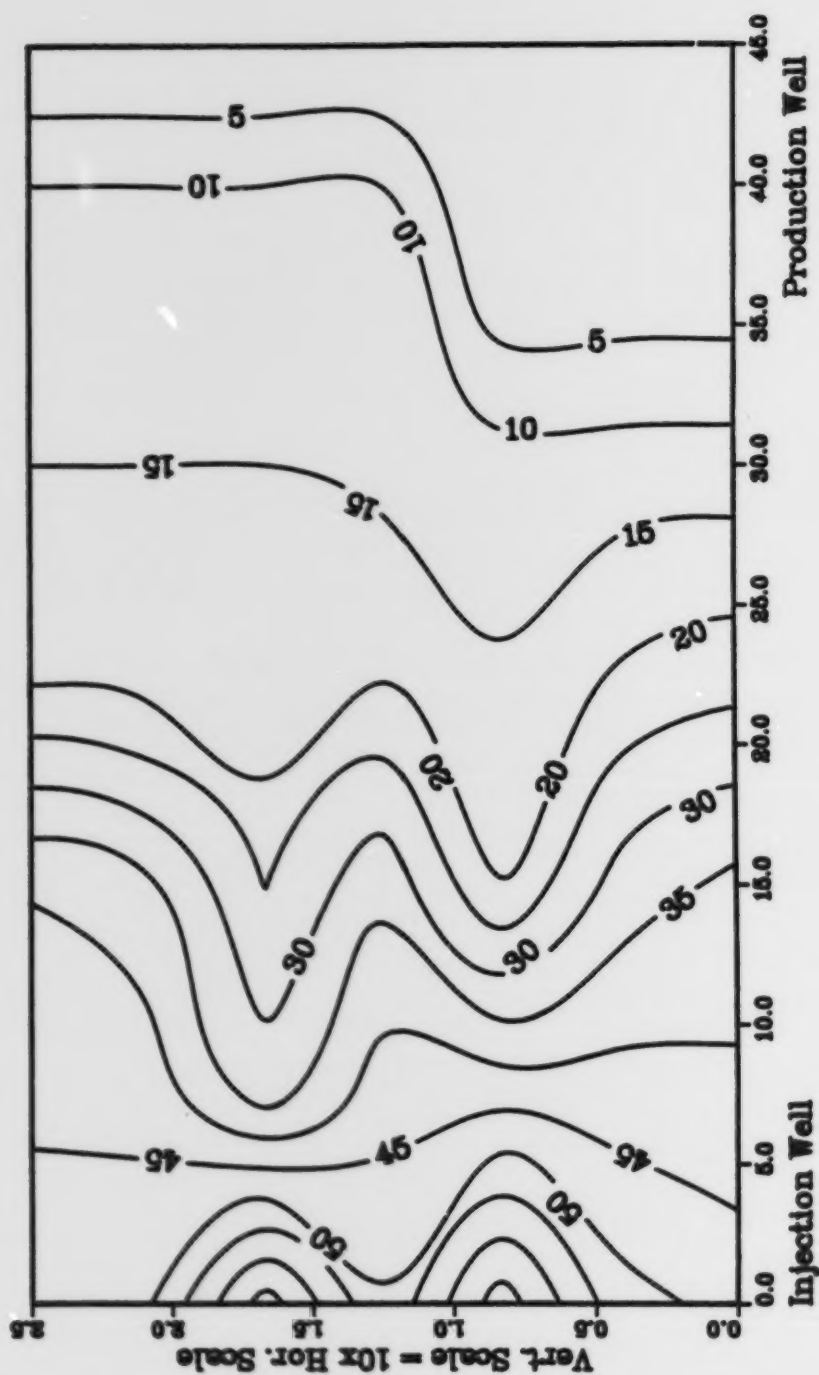


**Figure A.106 :Run 66 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

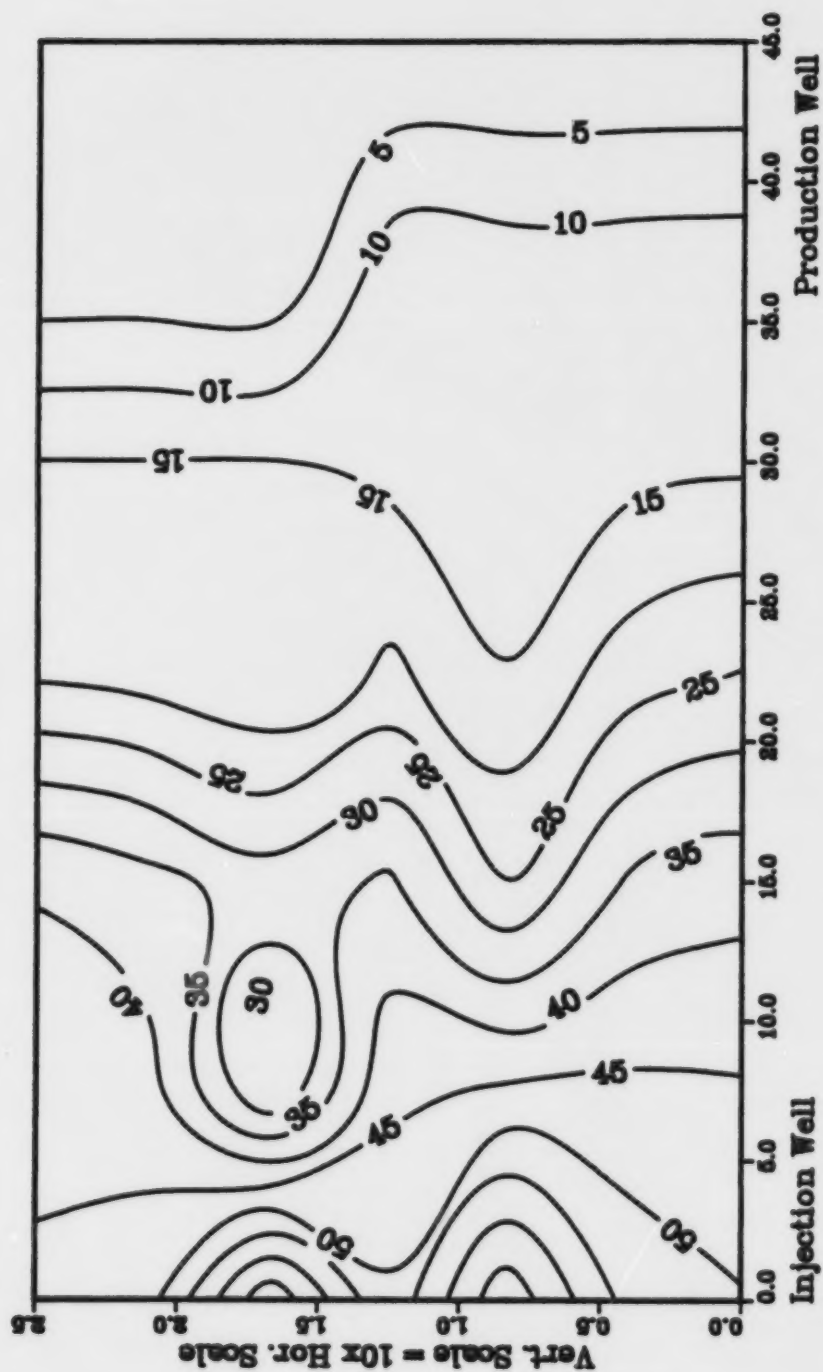


Figure A107 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.25 Pore Volumes Injected

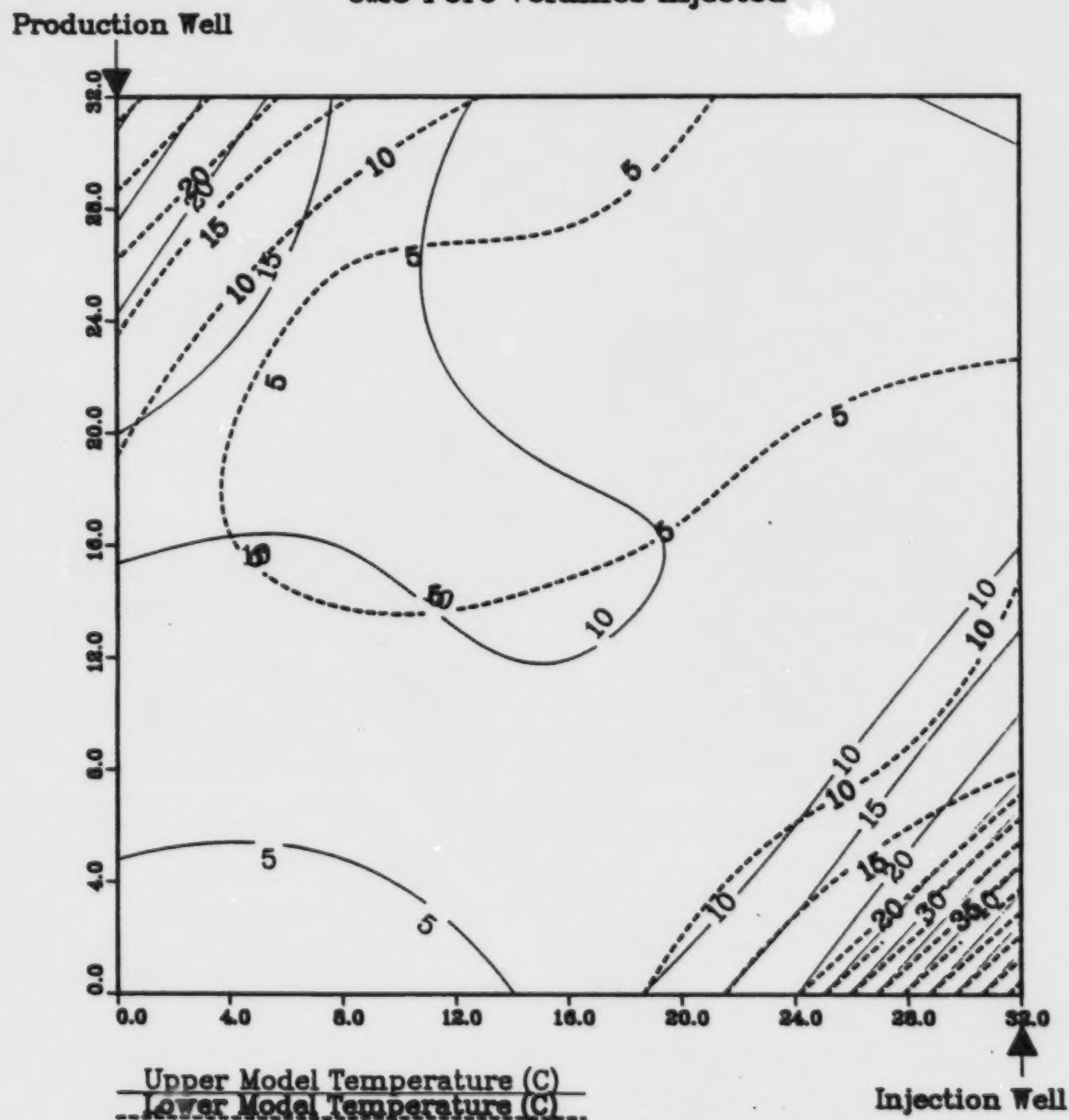


Figure A.108 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.50 Pore Volumes Injected

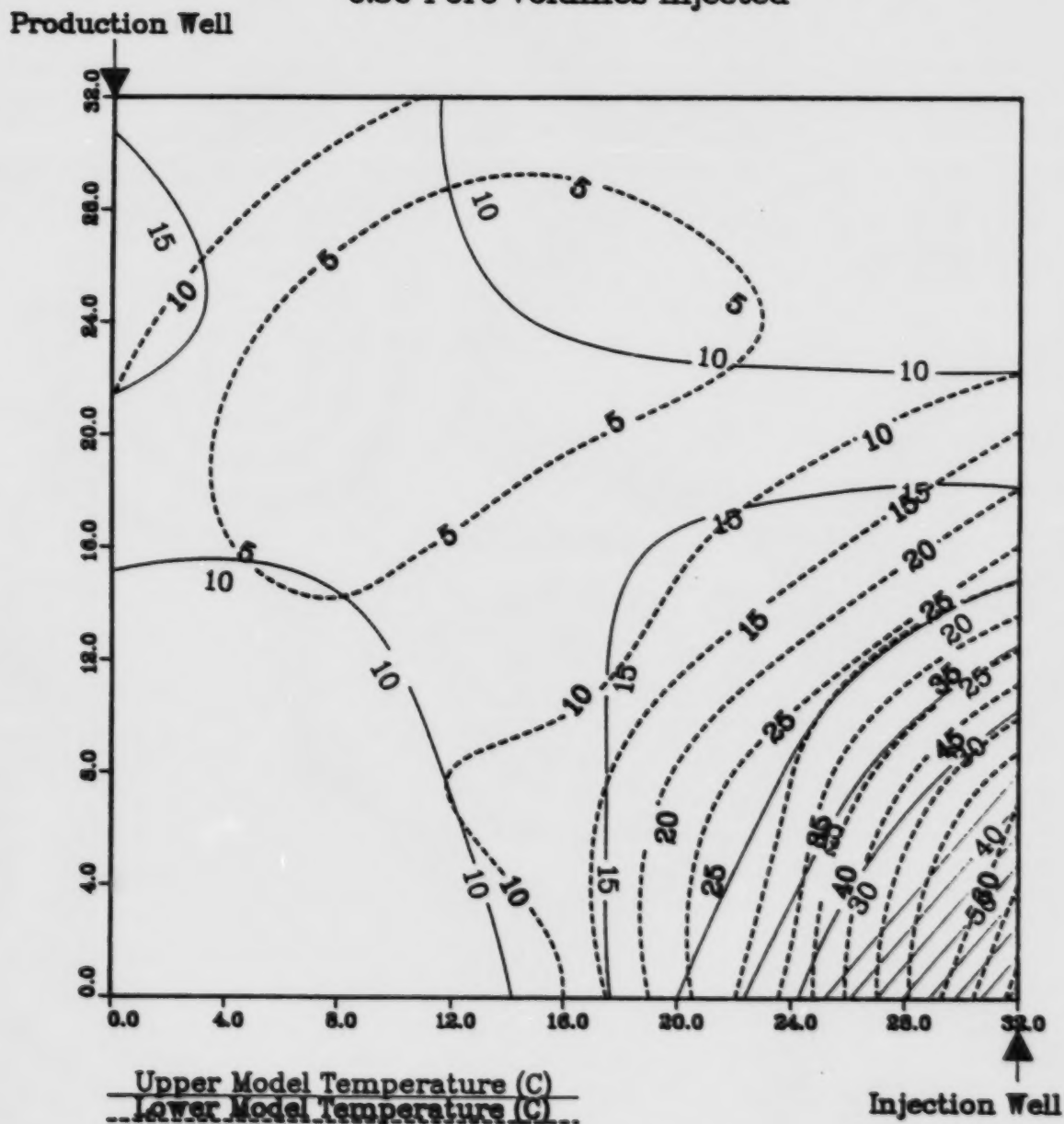


Figure A109 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
0.75 Pore Volumes Injected

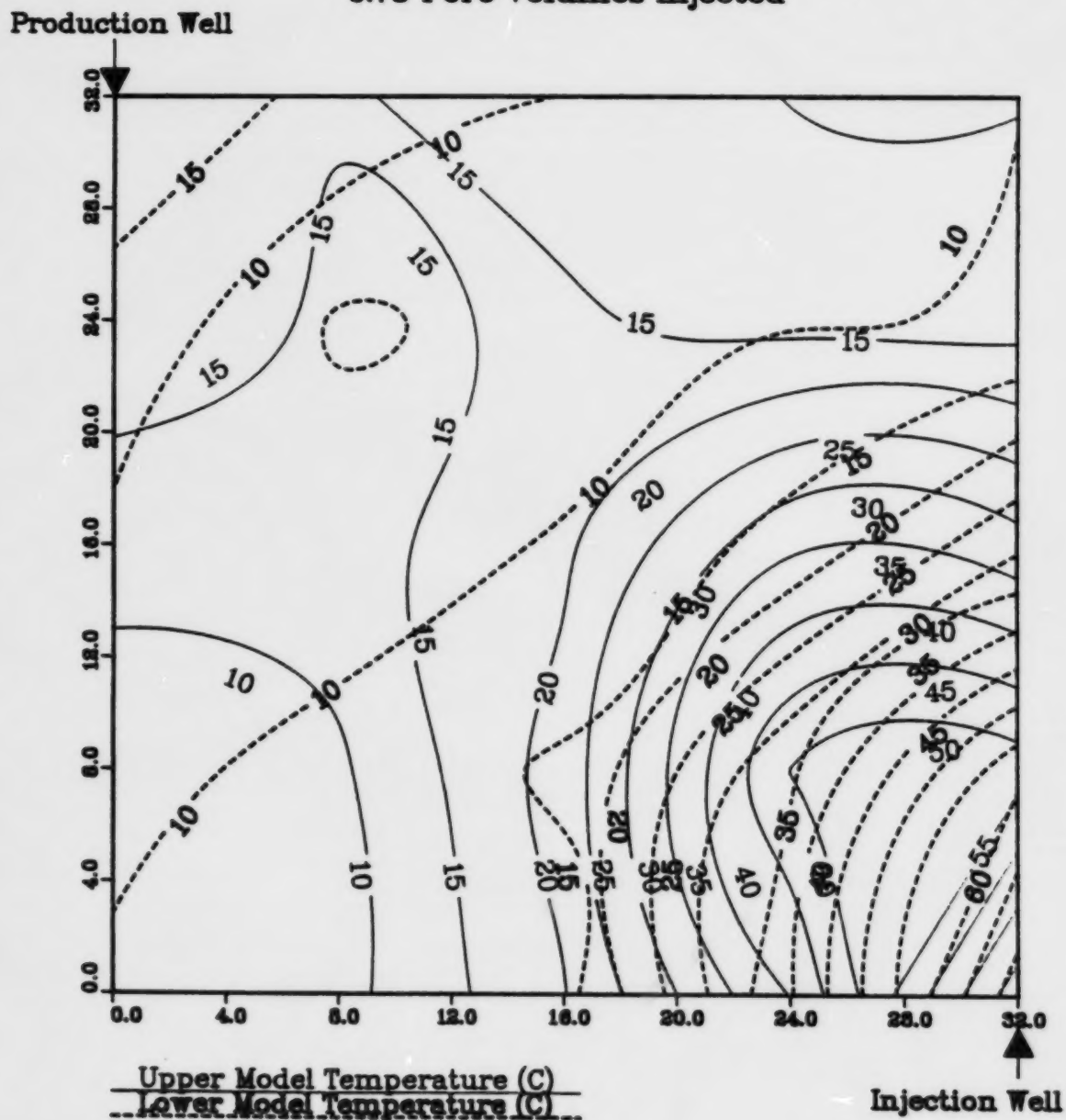


Figure A.110 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.00 Pore Volumes Injected

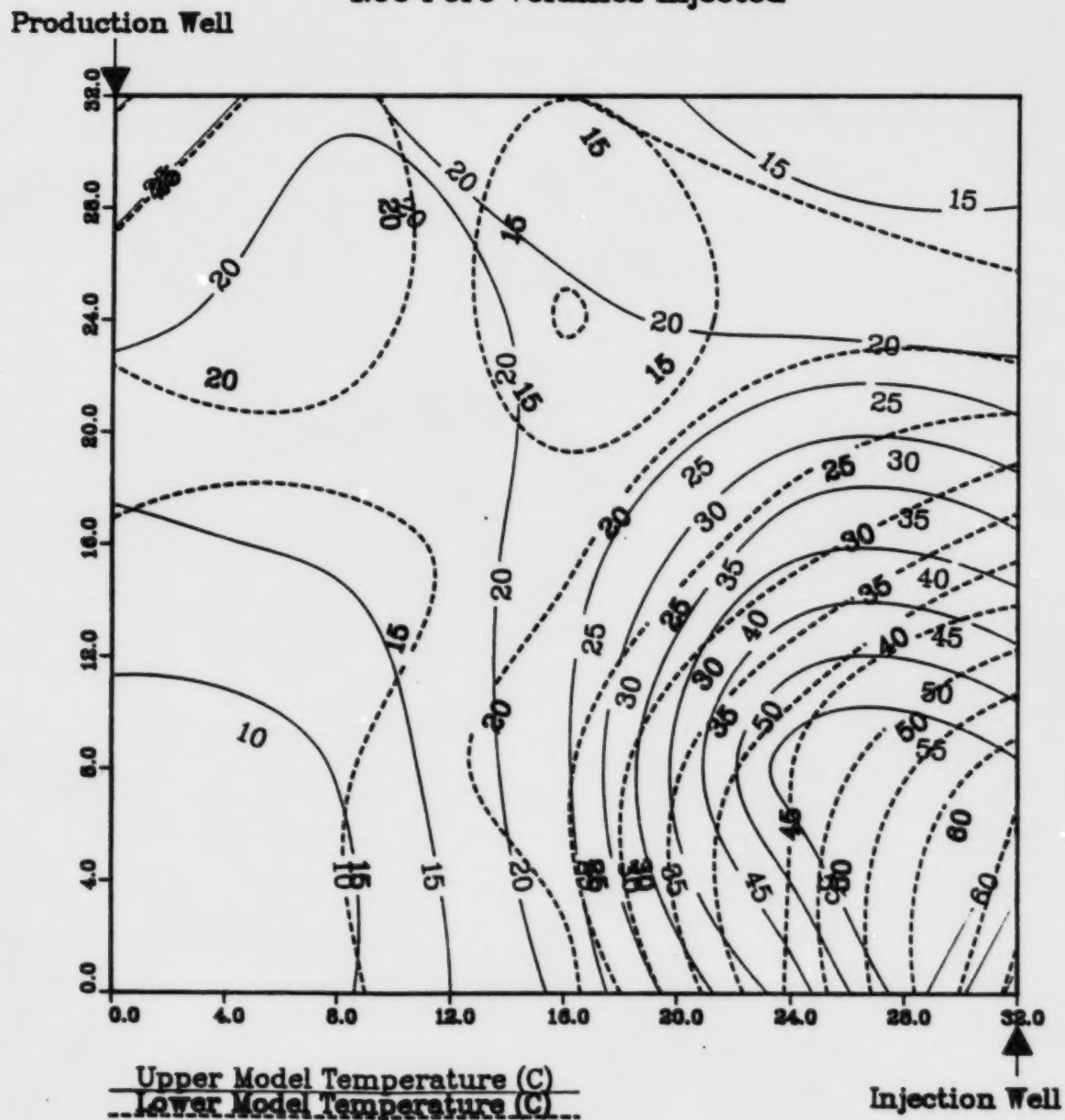
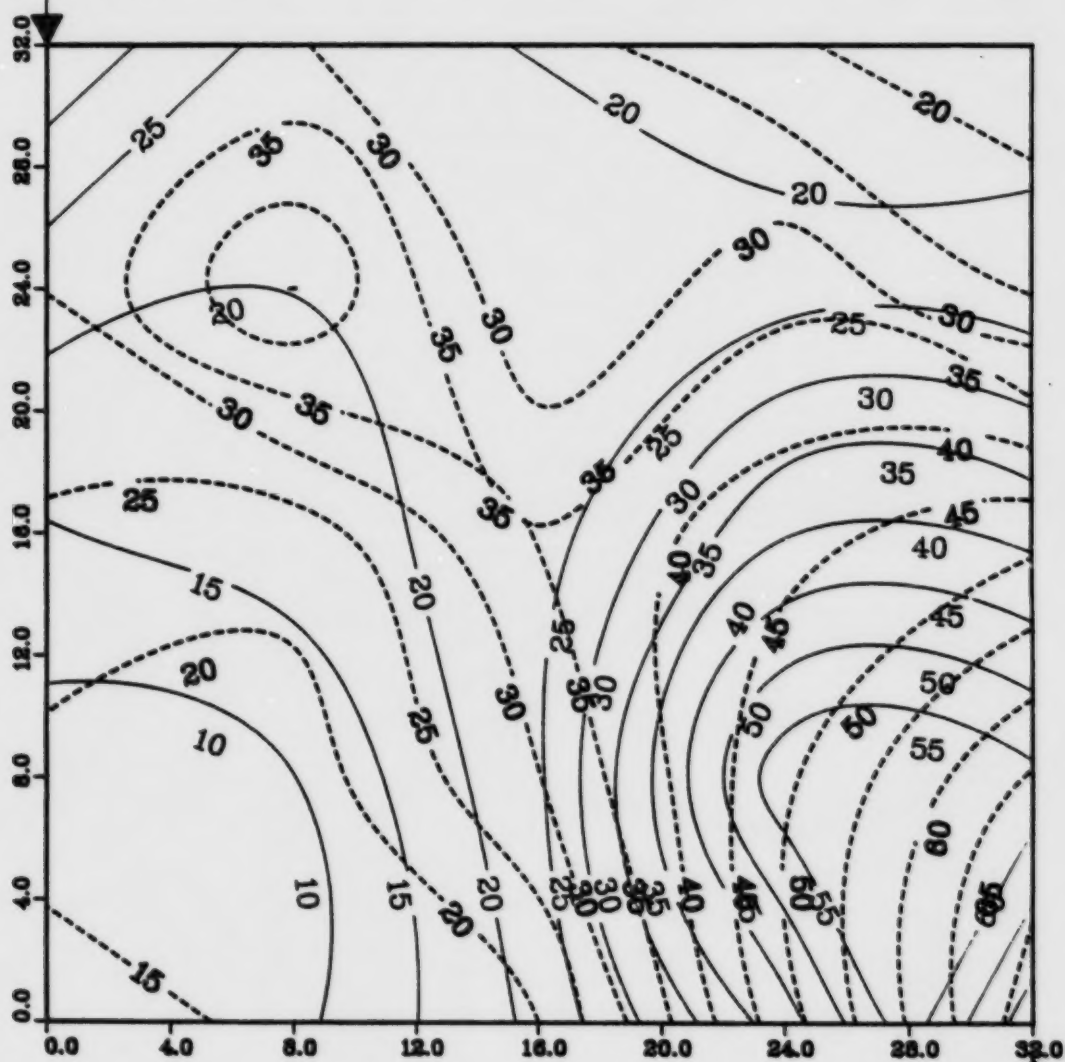


Figure A.111 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.112 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.50 Pore Volumes Injected

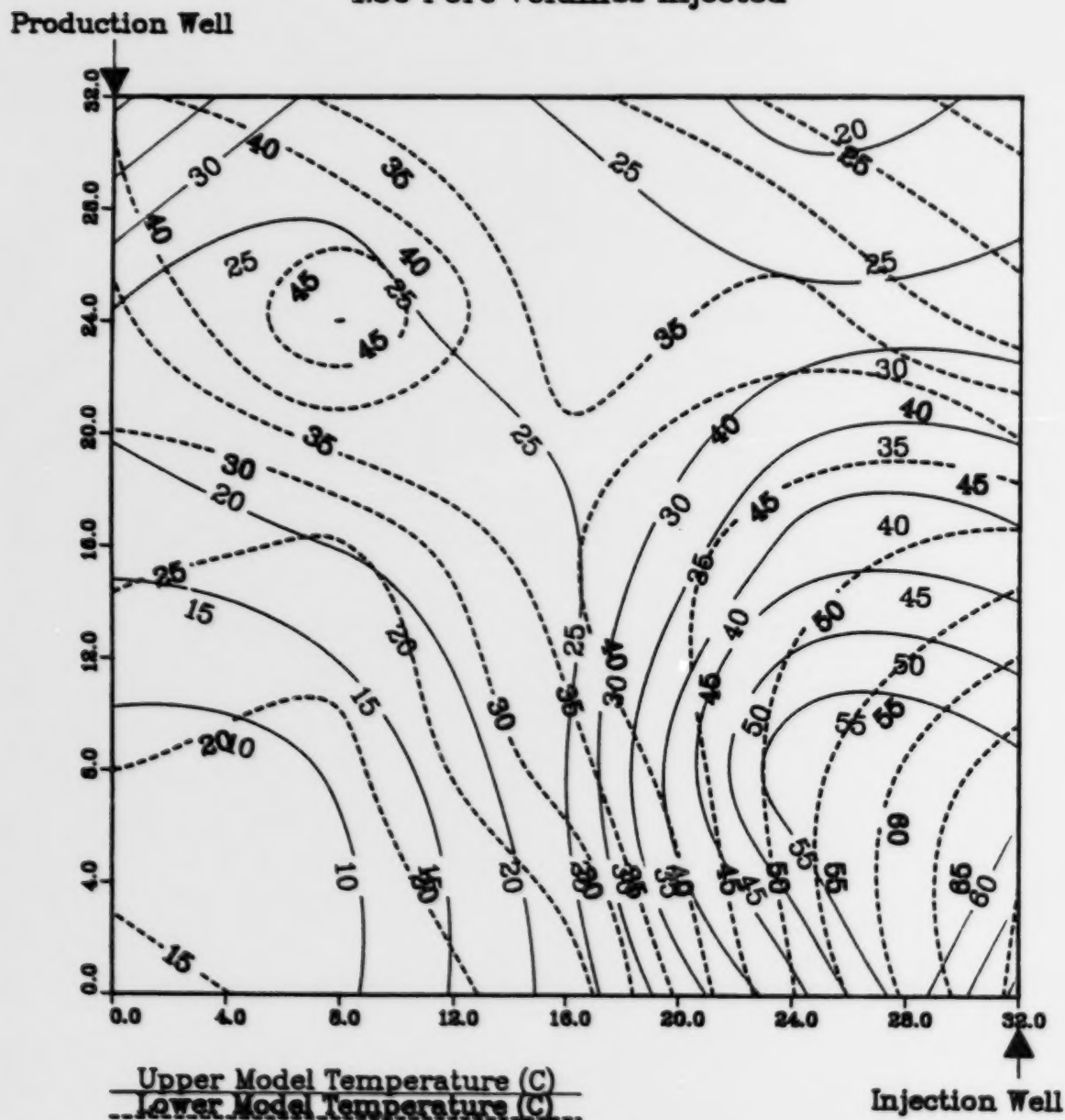
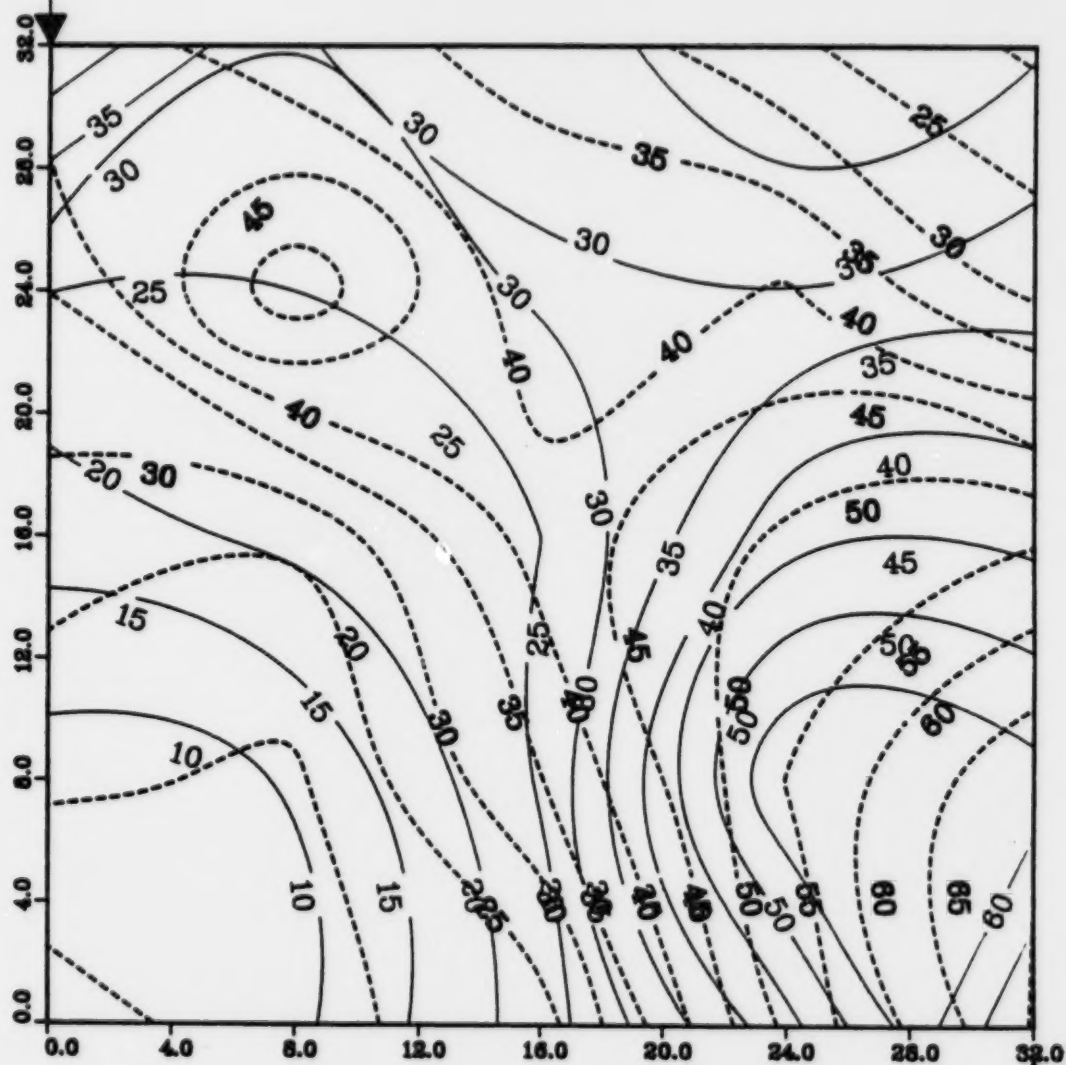


Figure A.113 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.114 : Run 67
Solvent-Steamflood in Homo. Model

Temperature Profile for
2.00 Pore Volumes Injected

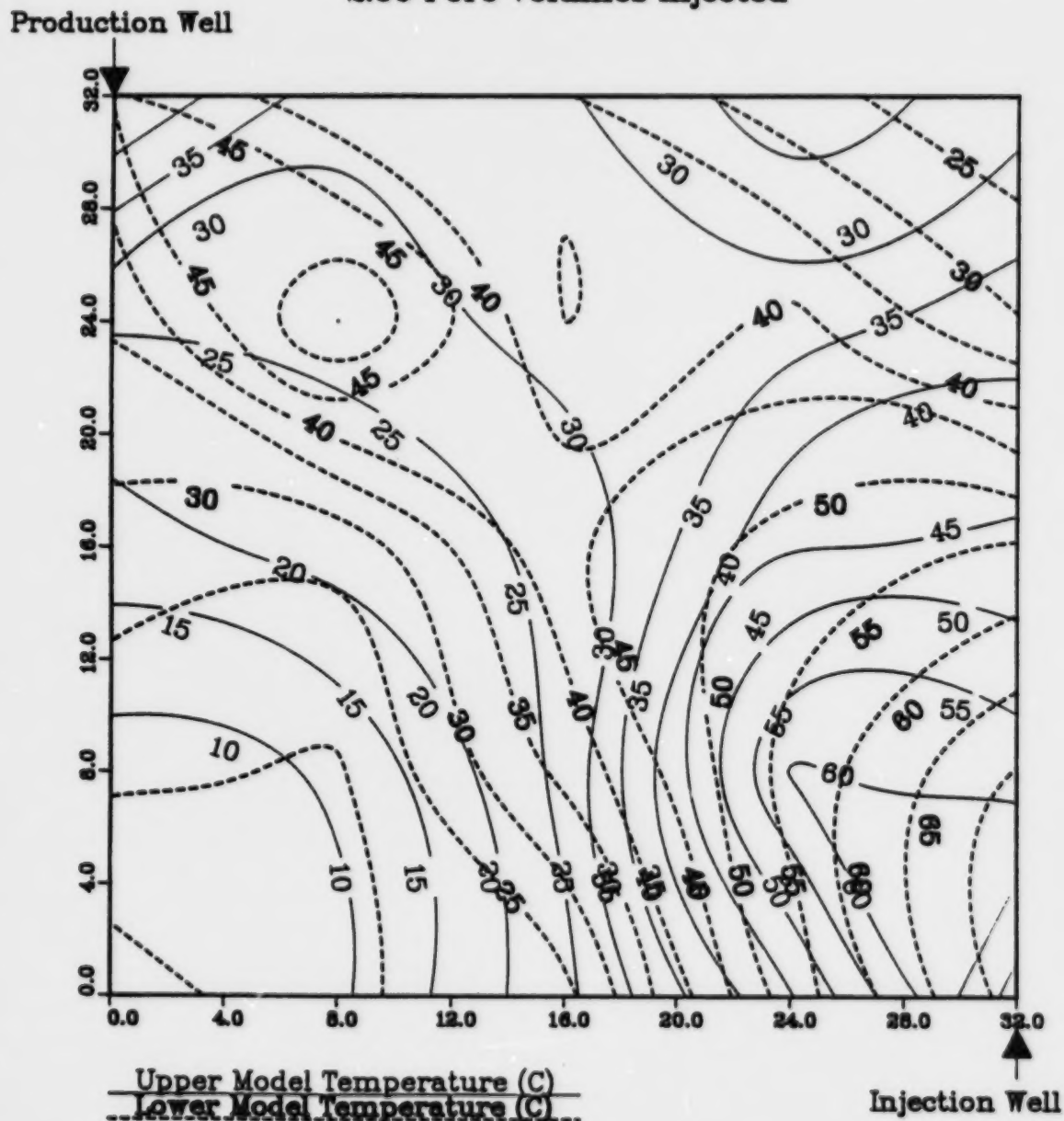


**Figure A.115 :Run 67 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

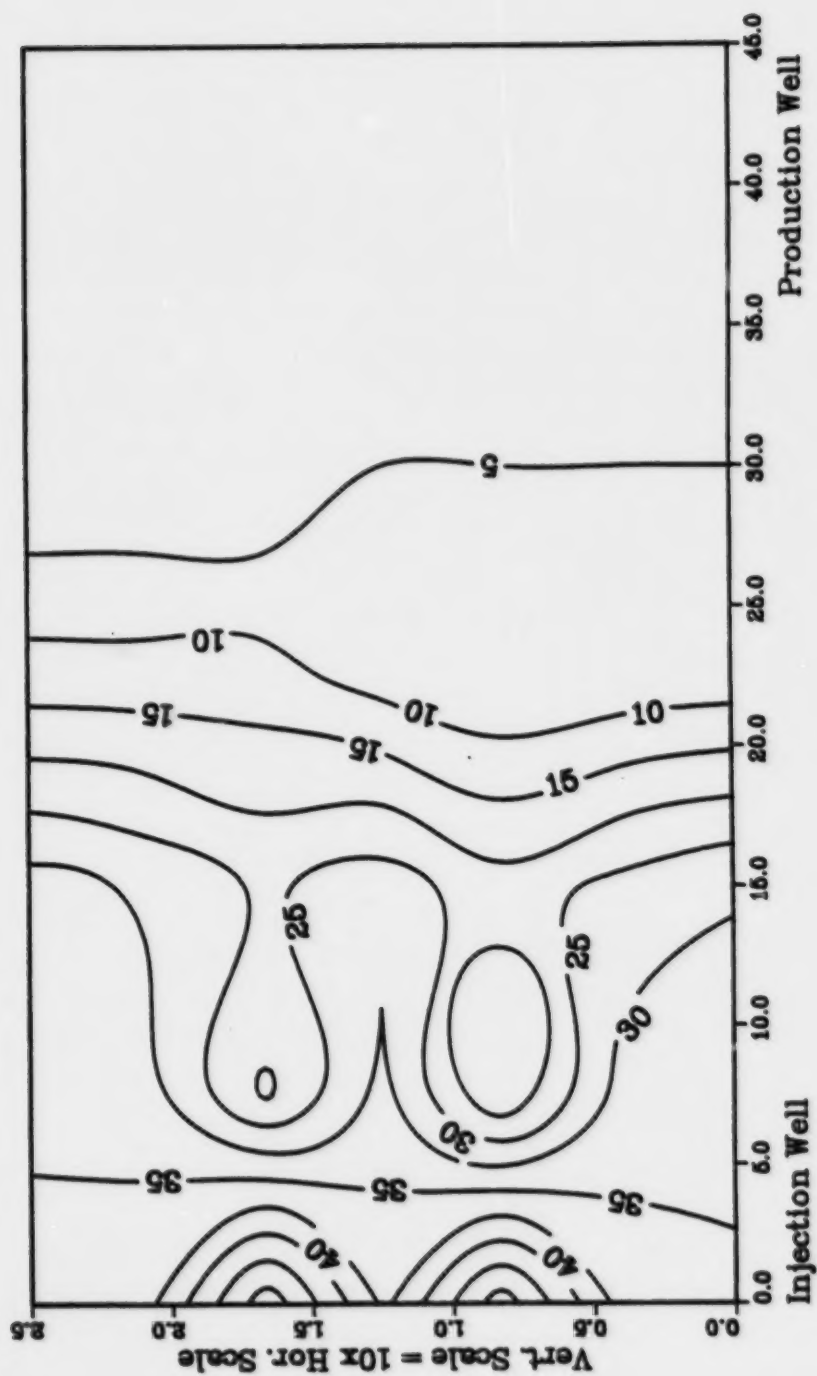


Figure A.116 :Run 67 Temp Profile
 Injector to Producer Cross-Section
 0.50 Pore Volumes Injected.

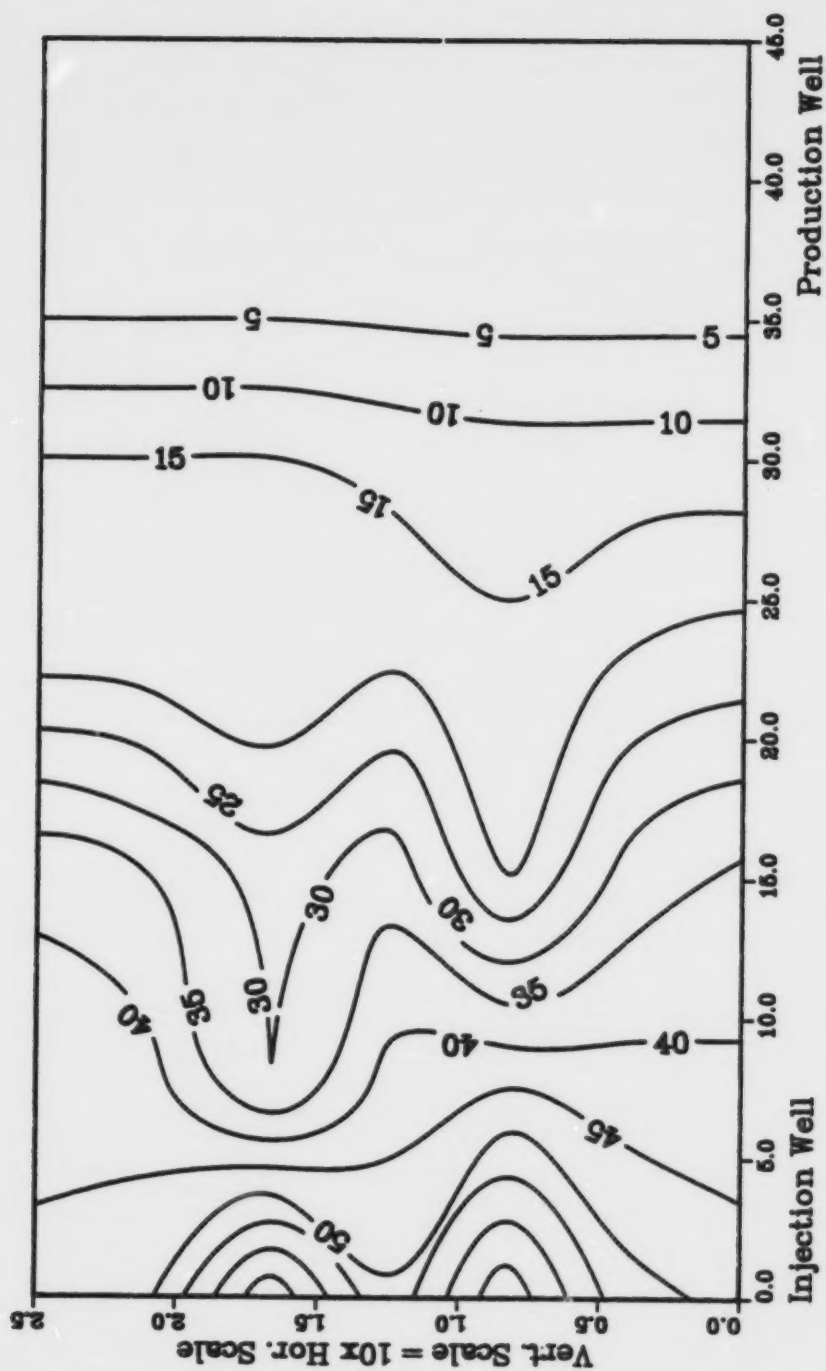


**Figure A.117 :Run 67 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

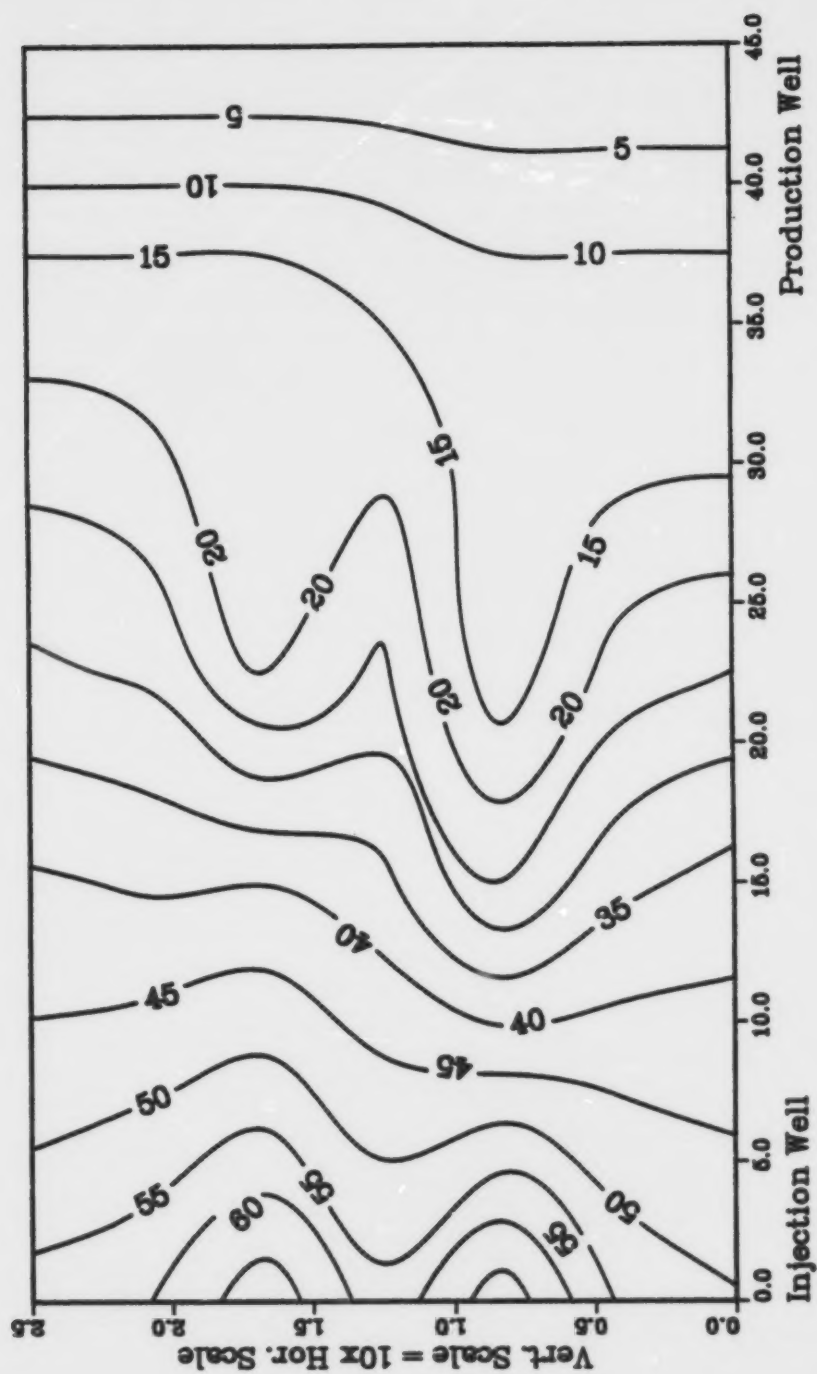


**Figure A.118 :Run 67 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

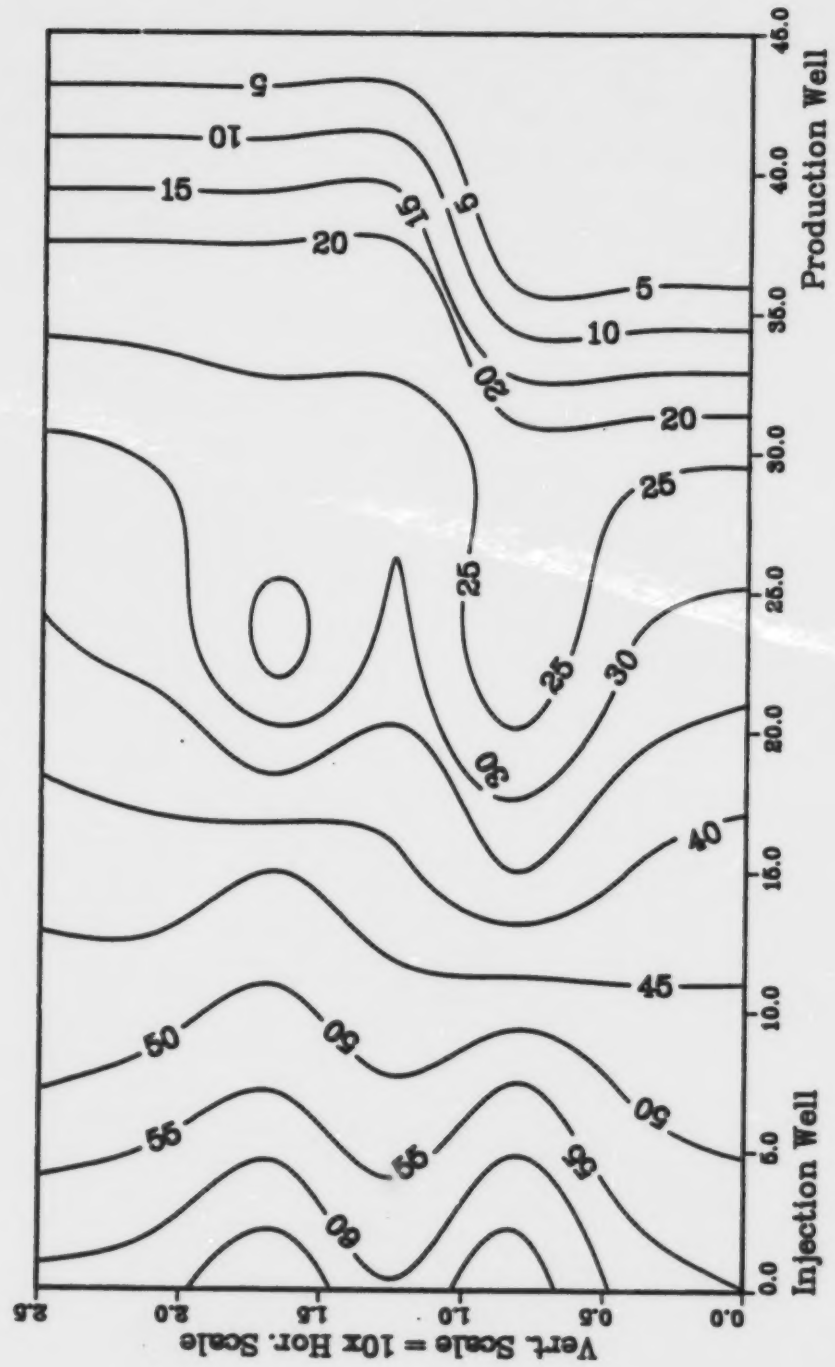


Figure A.119 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well

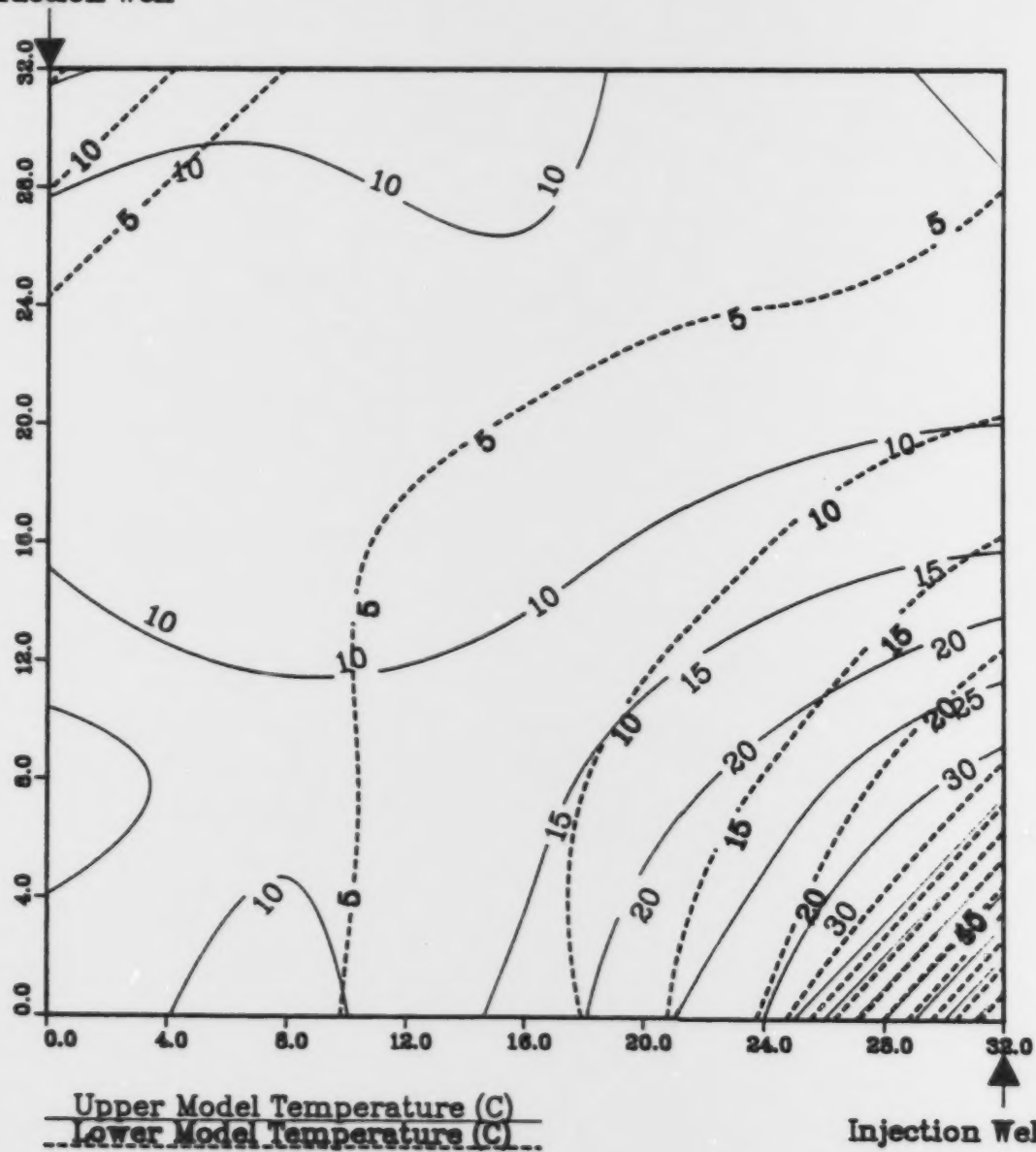


Figure A.120 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

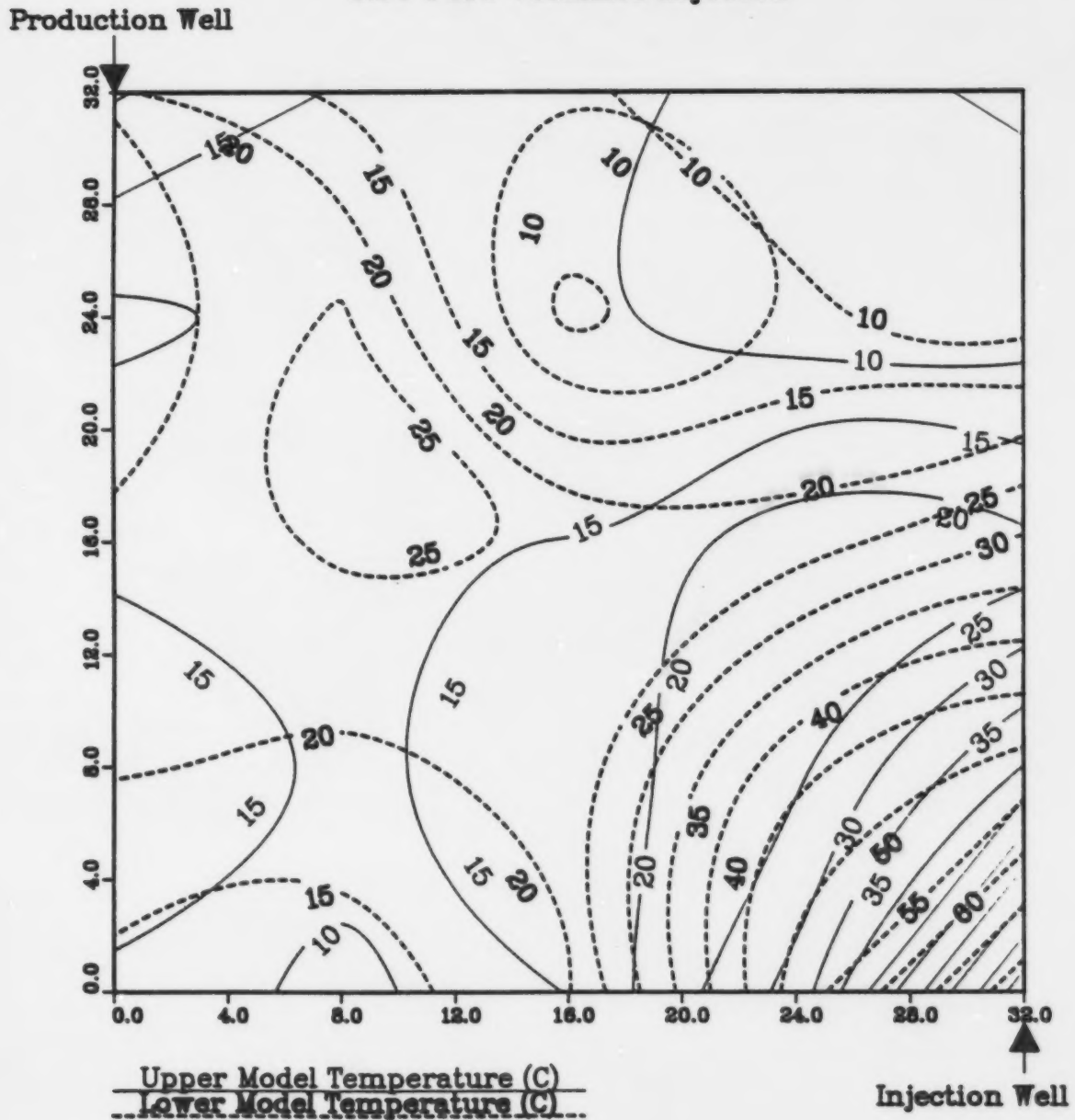


Figure A.121 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

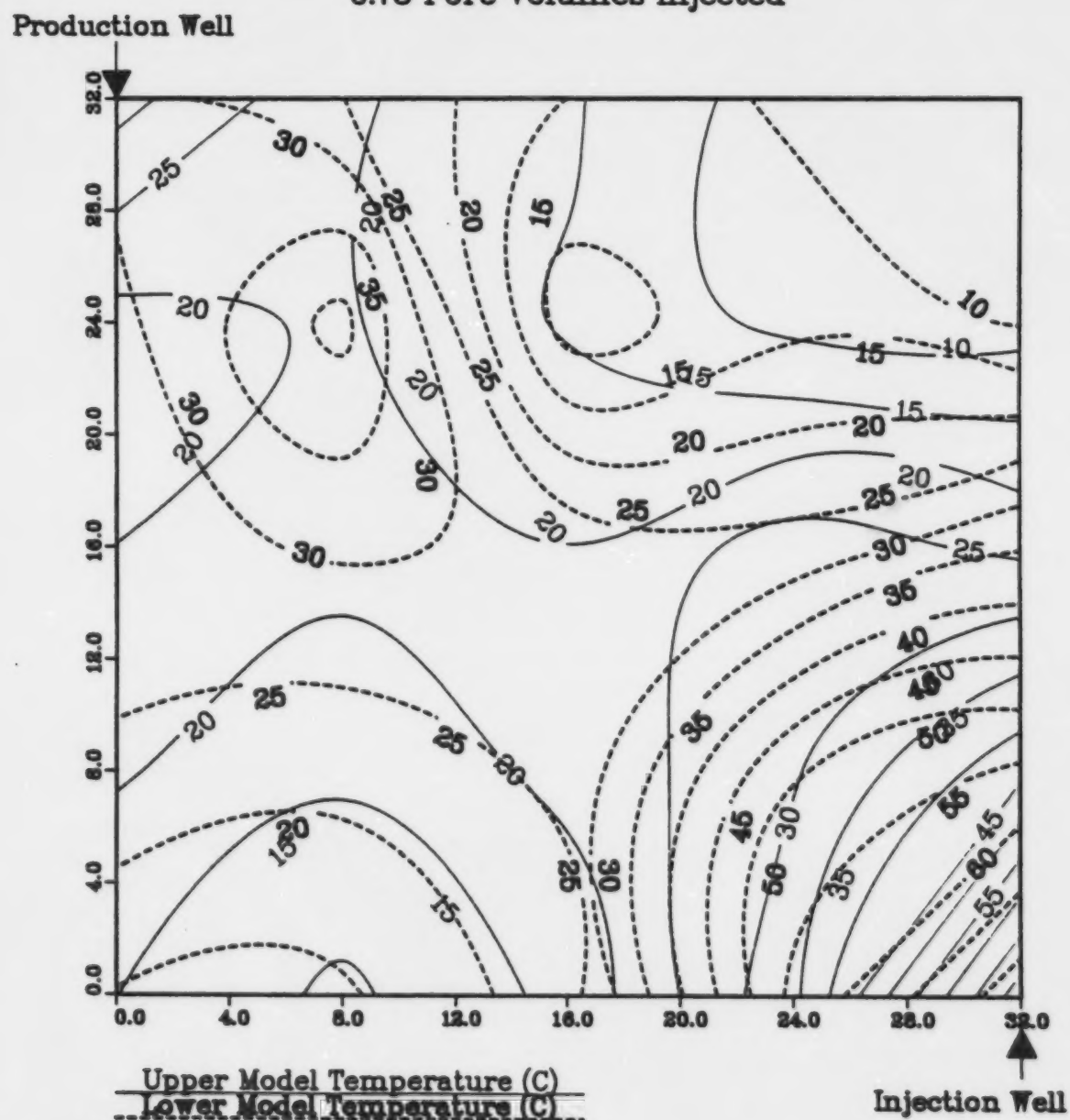
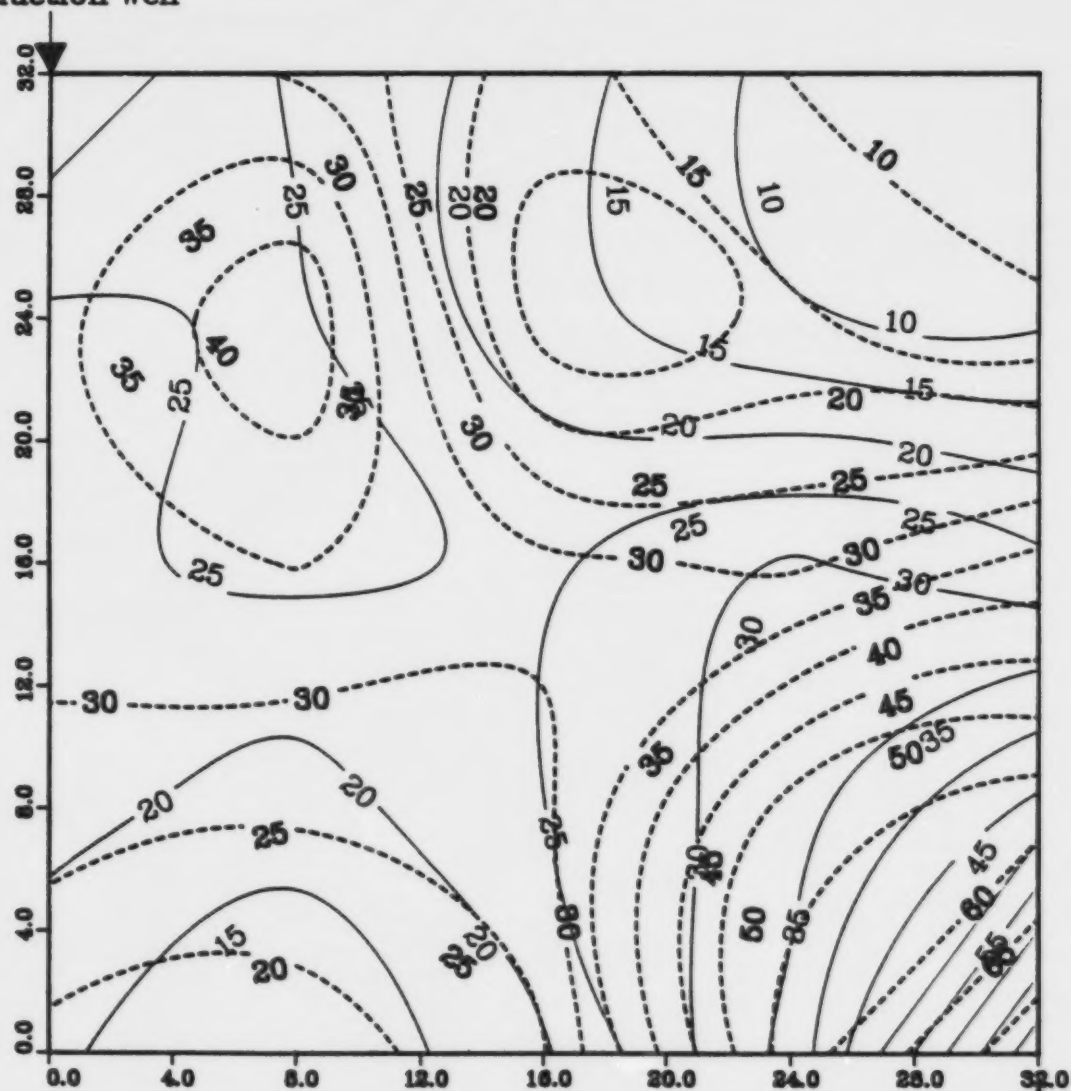


Figure A122 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.123 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

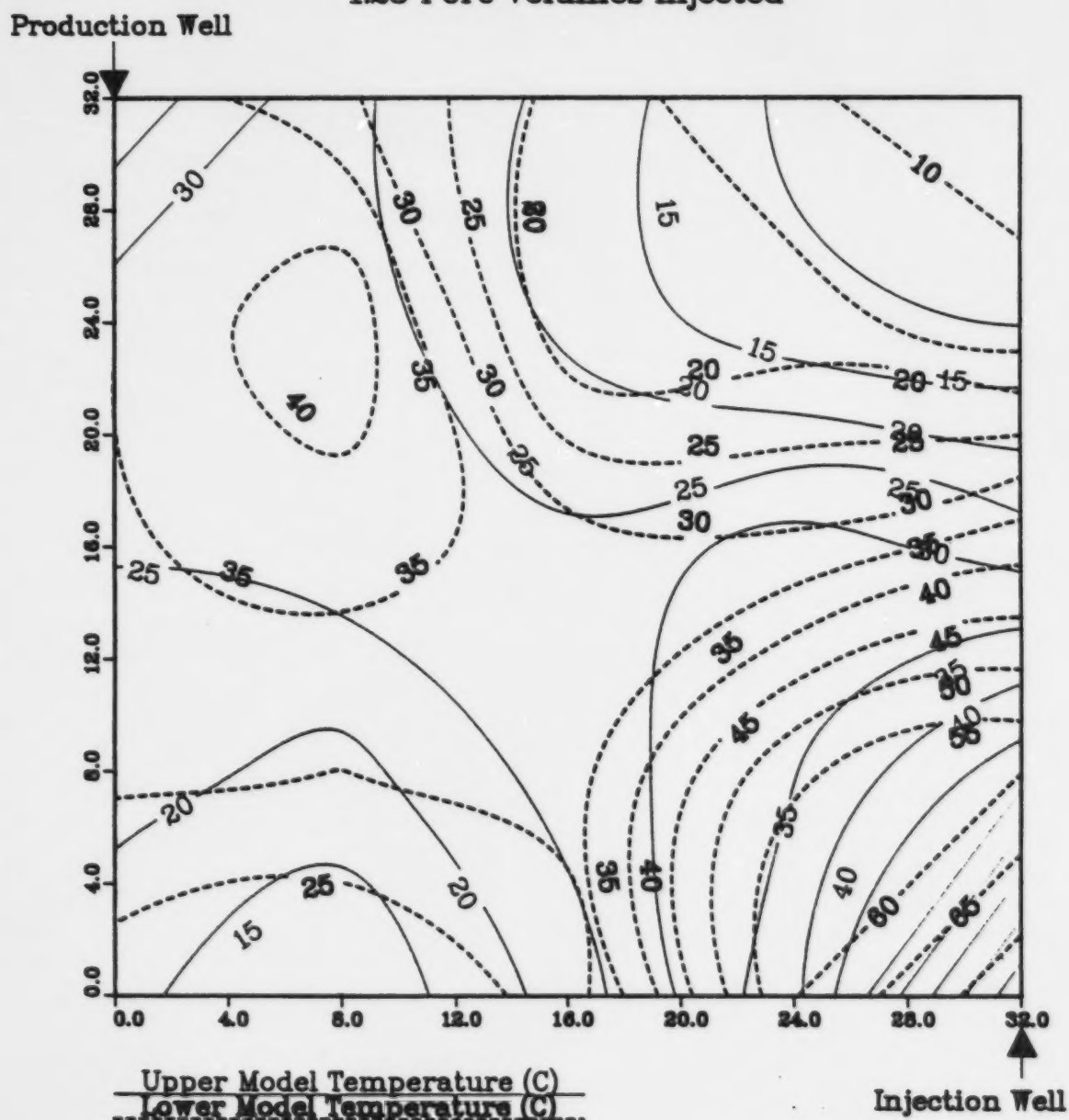


Figure A.124 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well

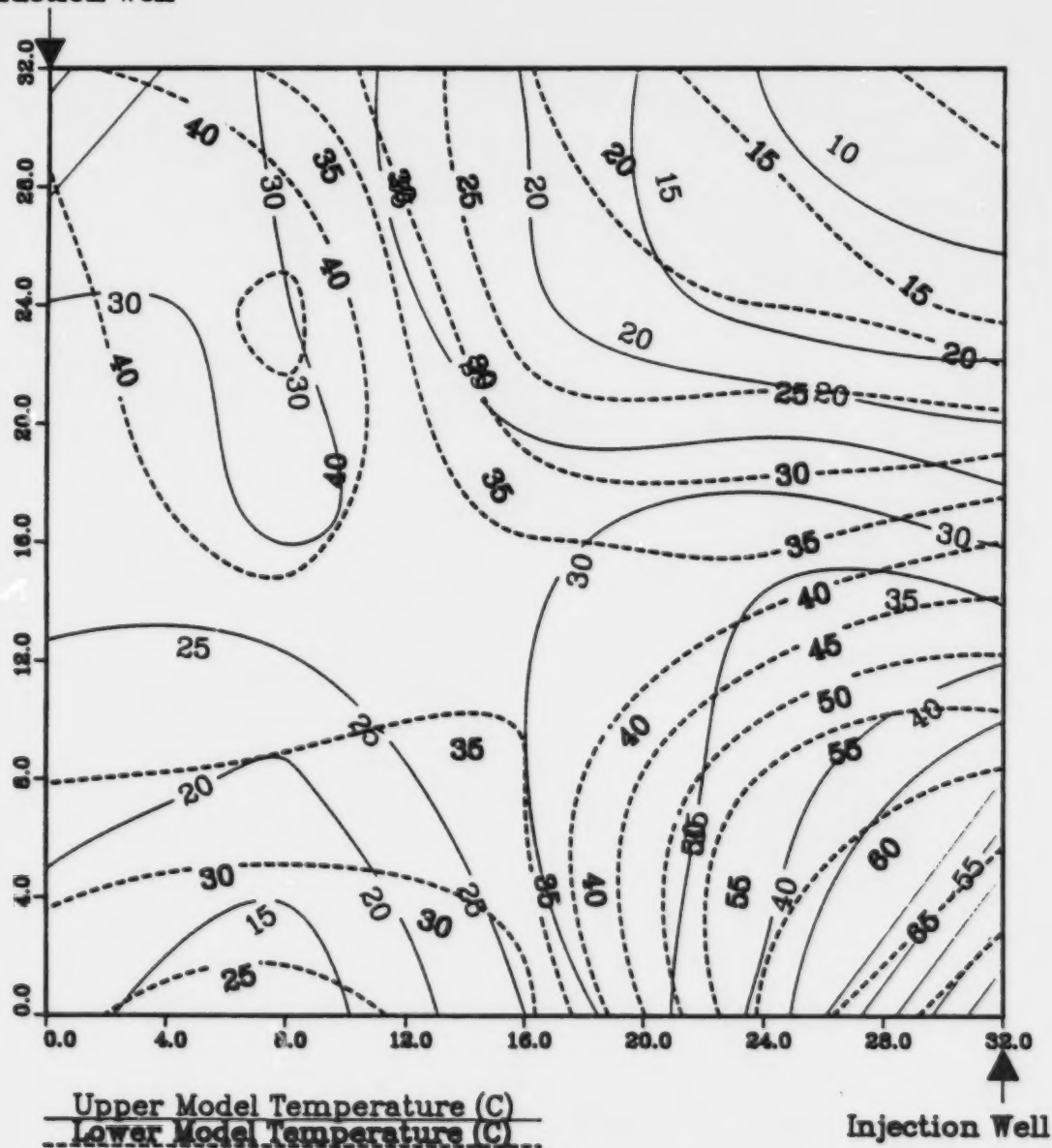
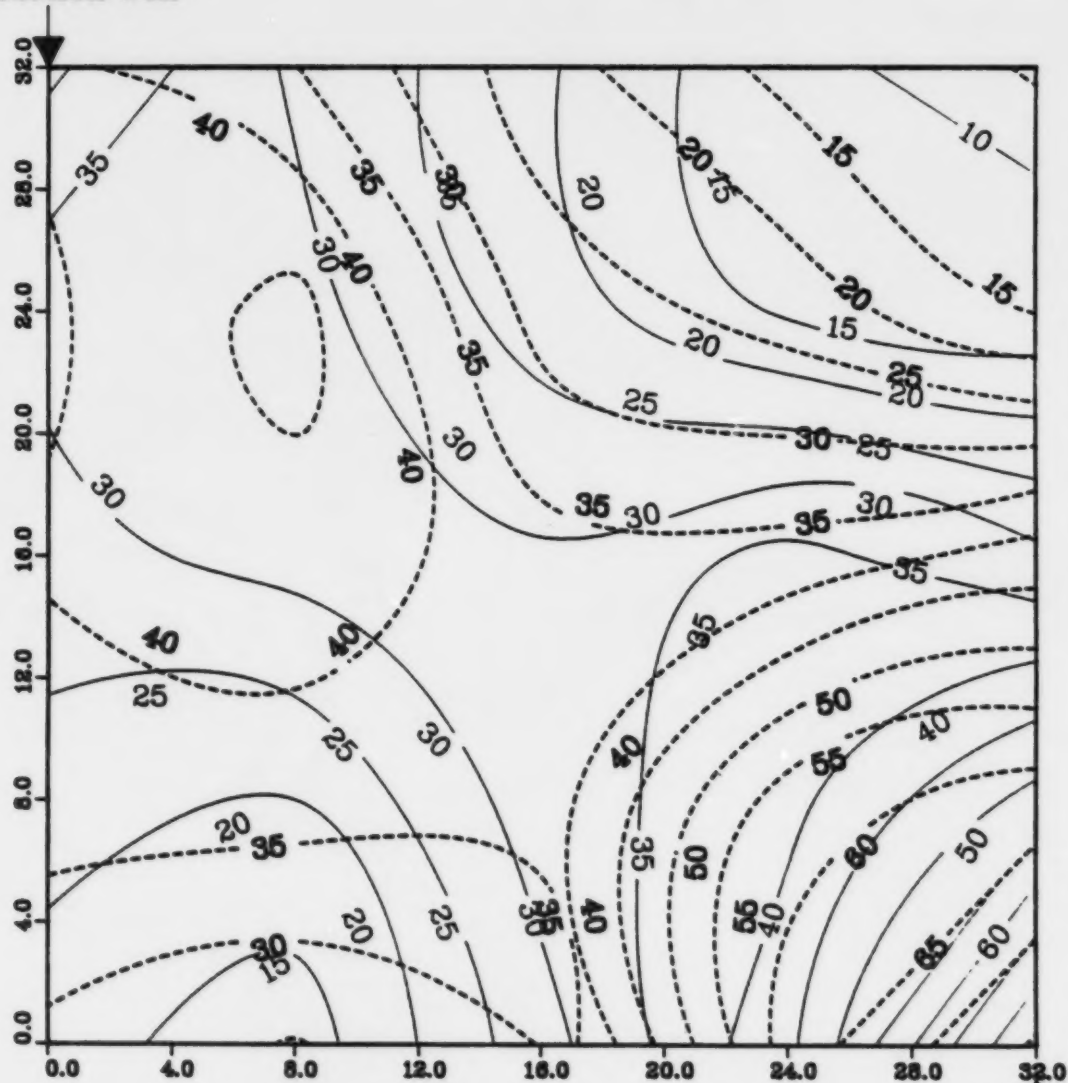


Figure A.125 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

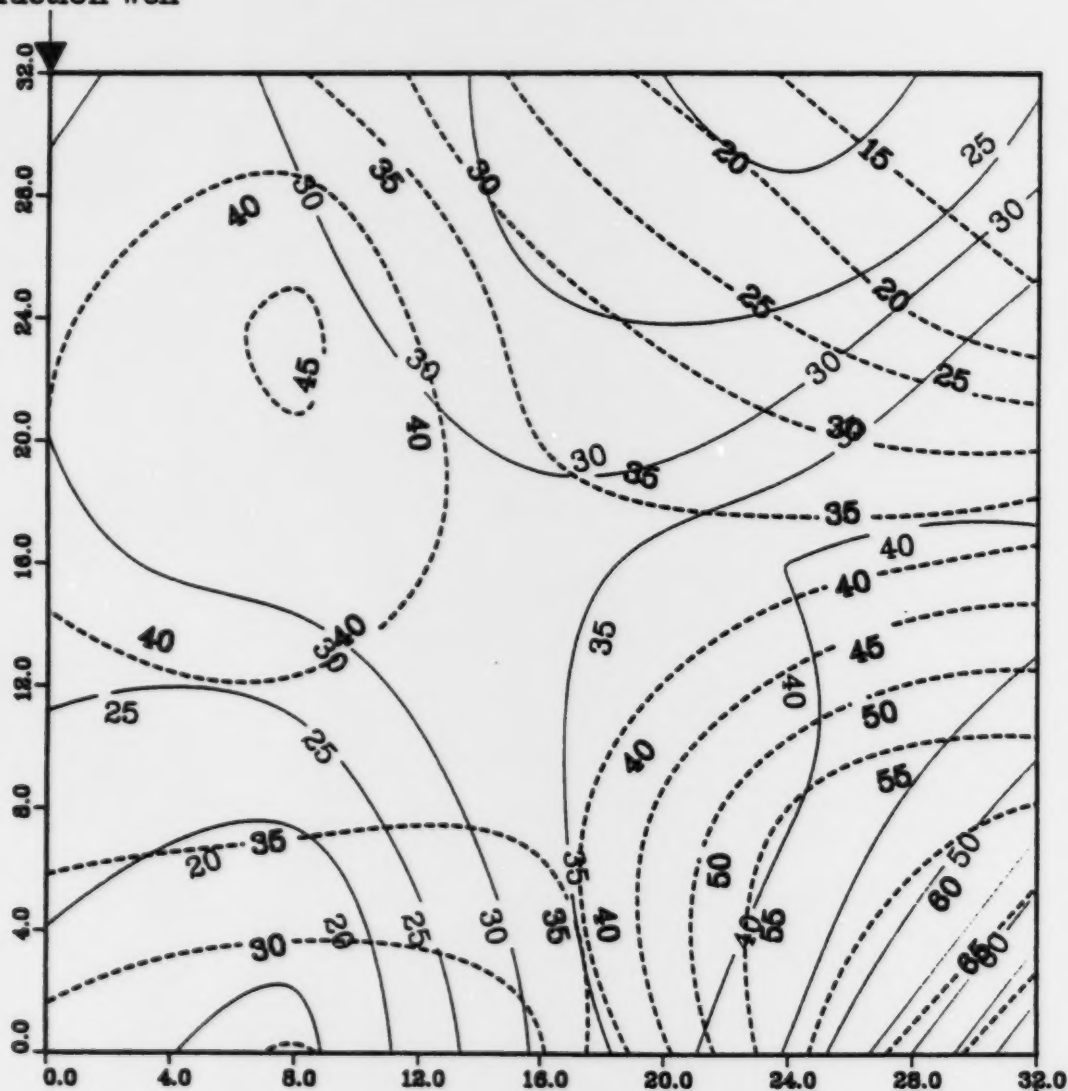
Lower Model Temperature (C)

Injection Well

Figure A.126 : Run 49
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.127 :Run 49 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

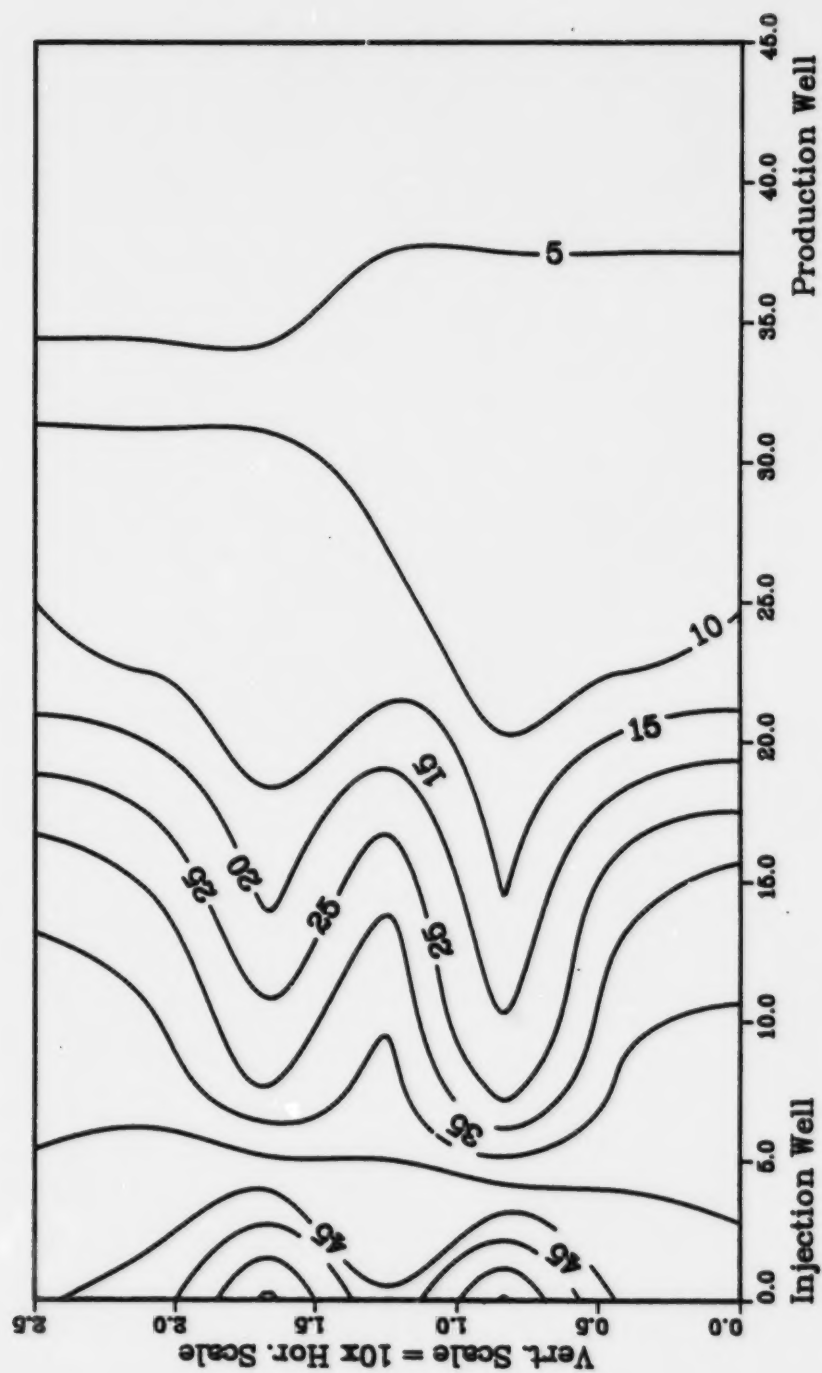


**Figure A.128 :Run 49 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

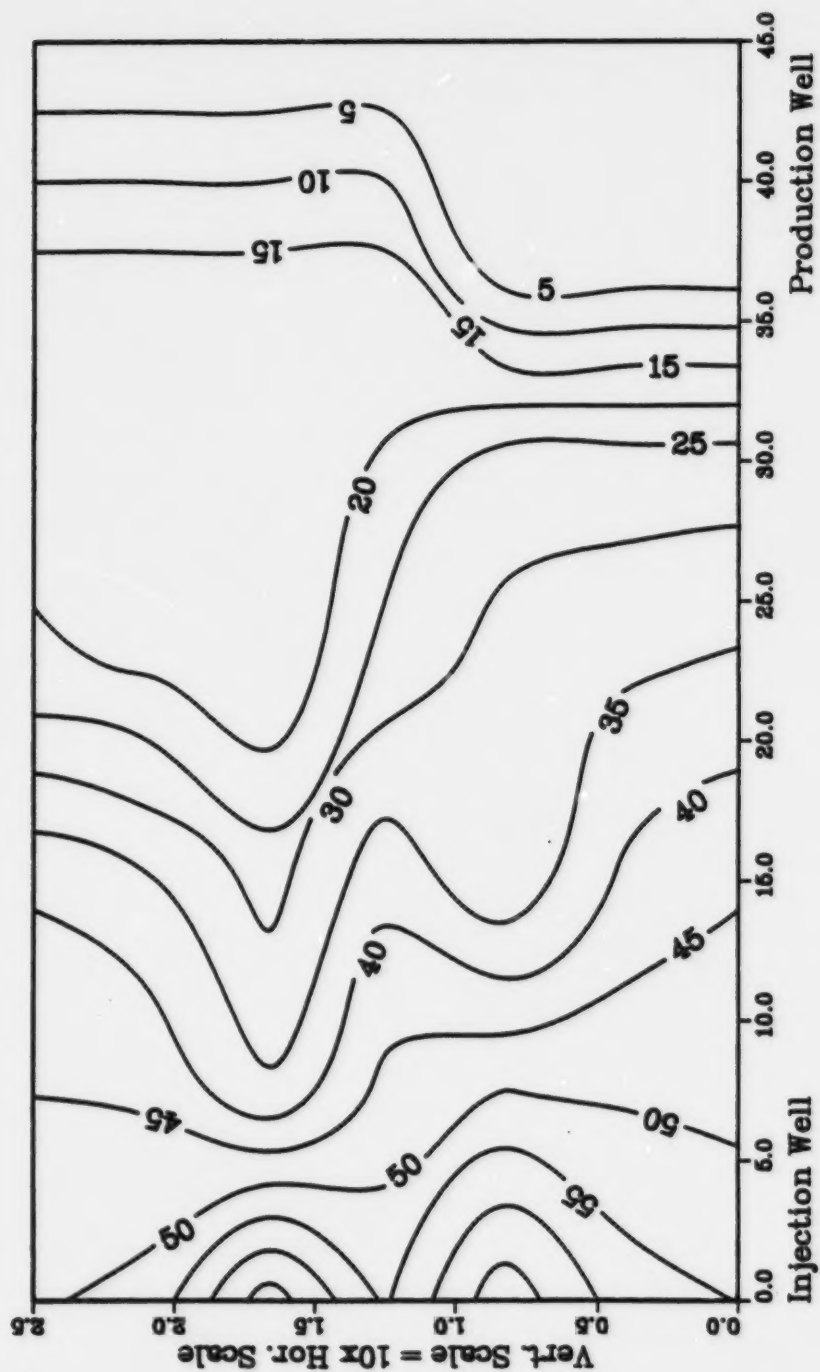


**Figure A.129 :Run 49 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

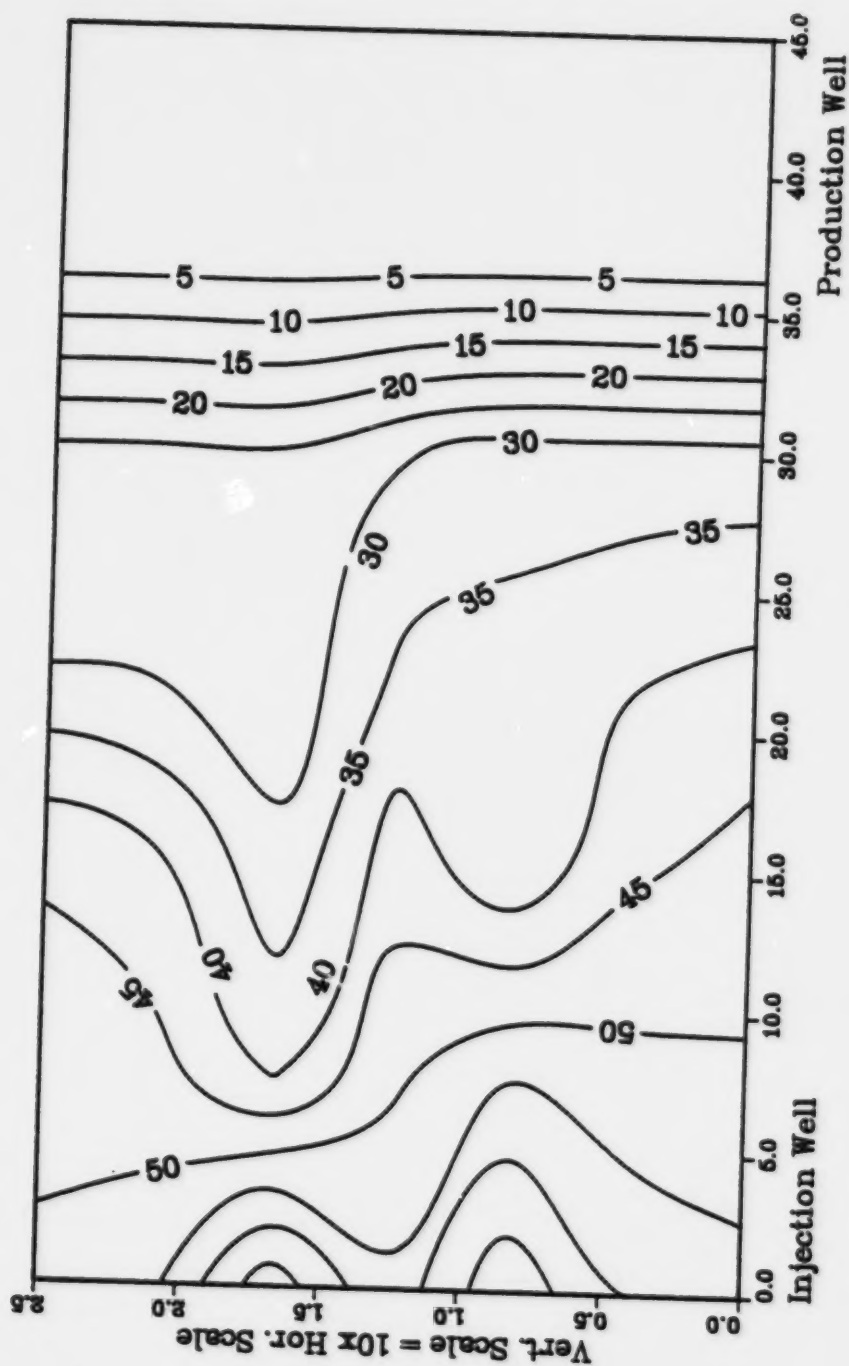


**Figure A.130 :Run 49 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

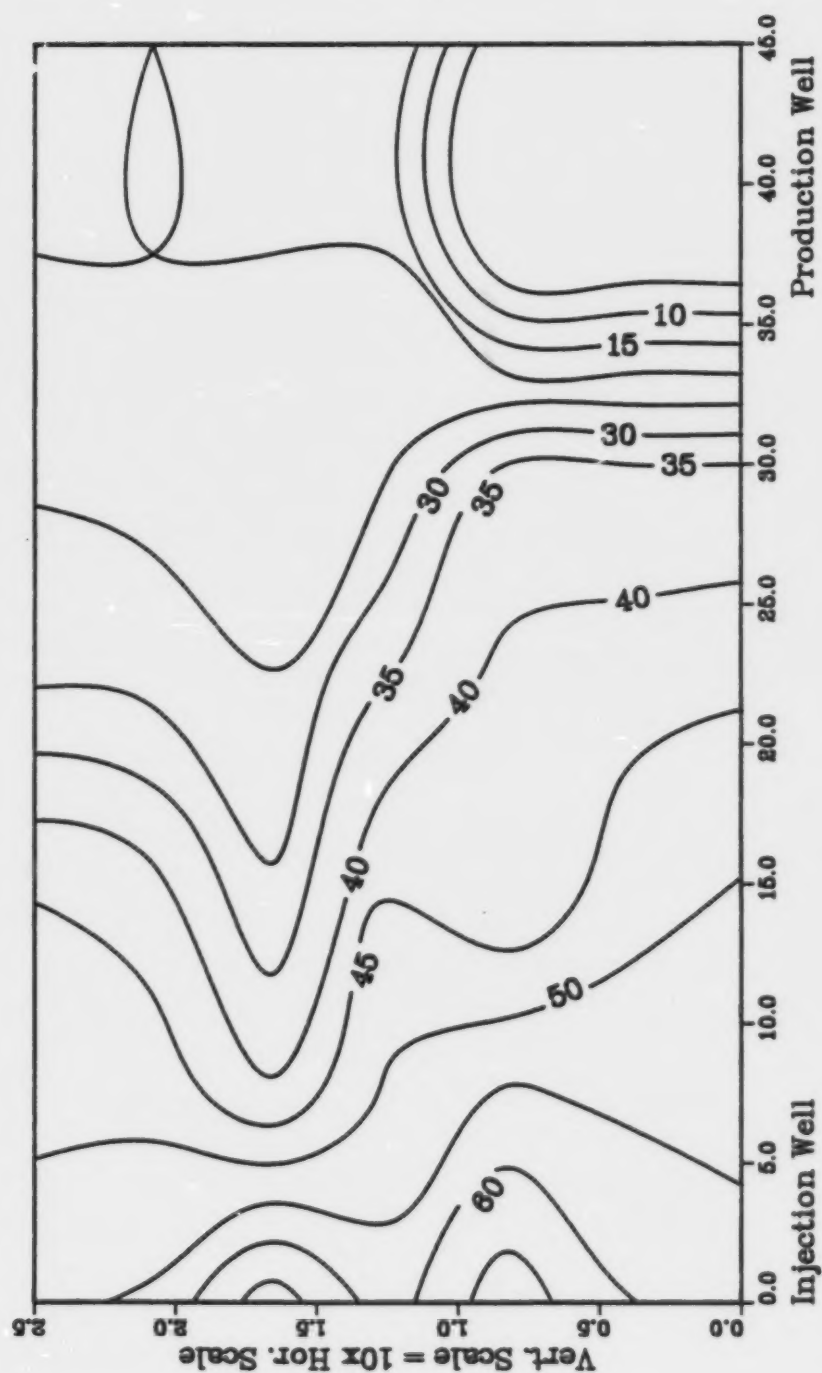


Figure A.131 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well

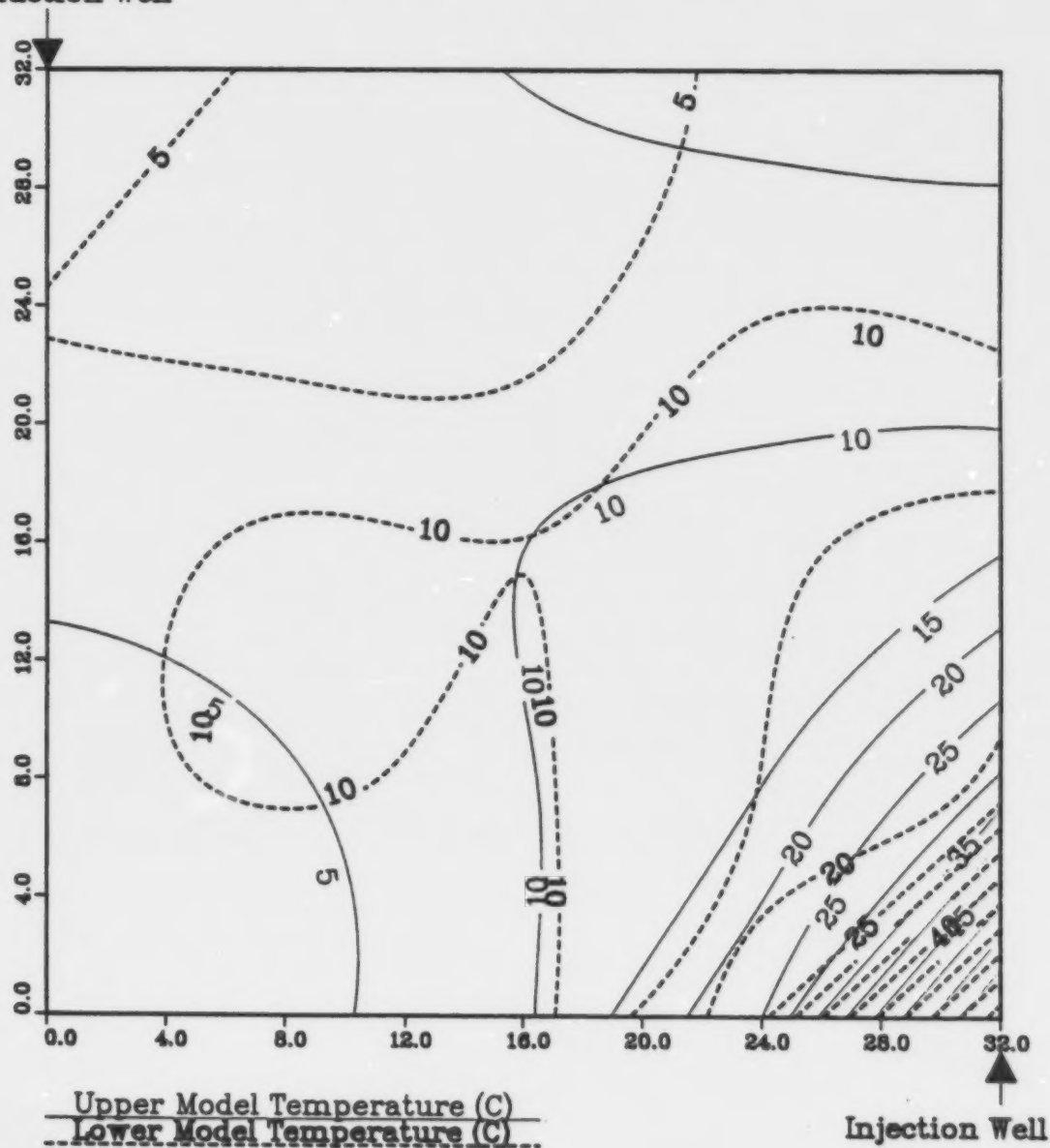


Figure A.132 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

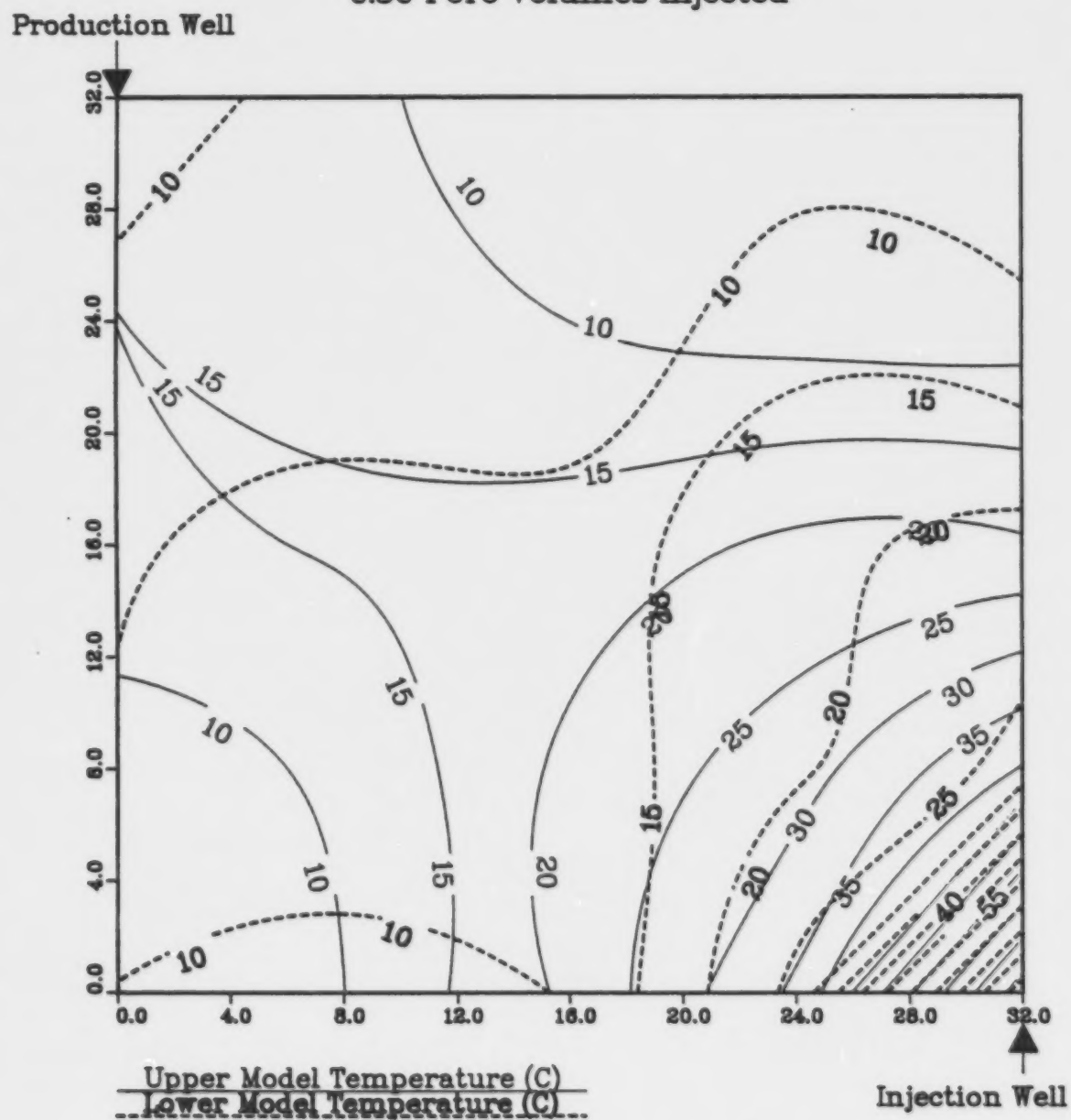
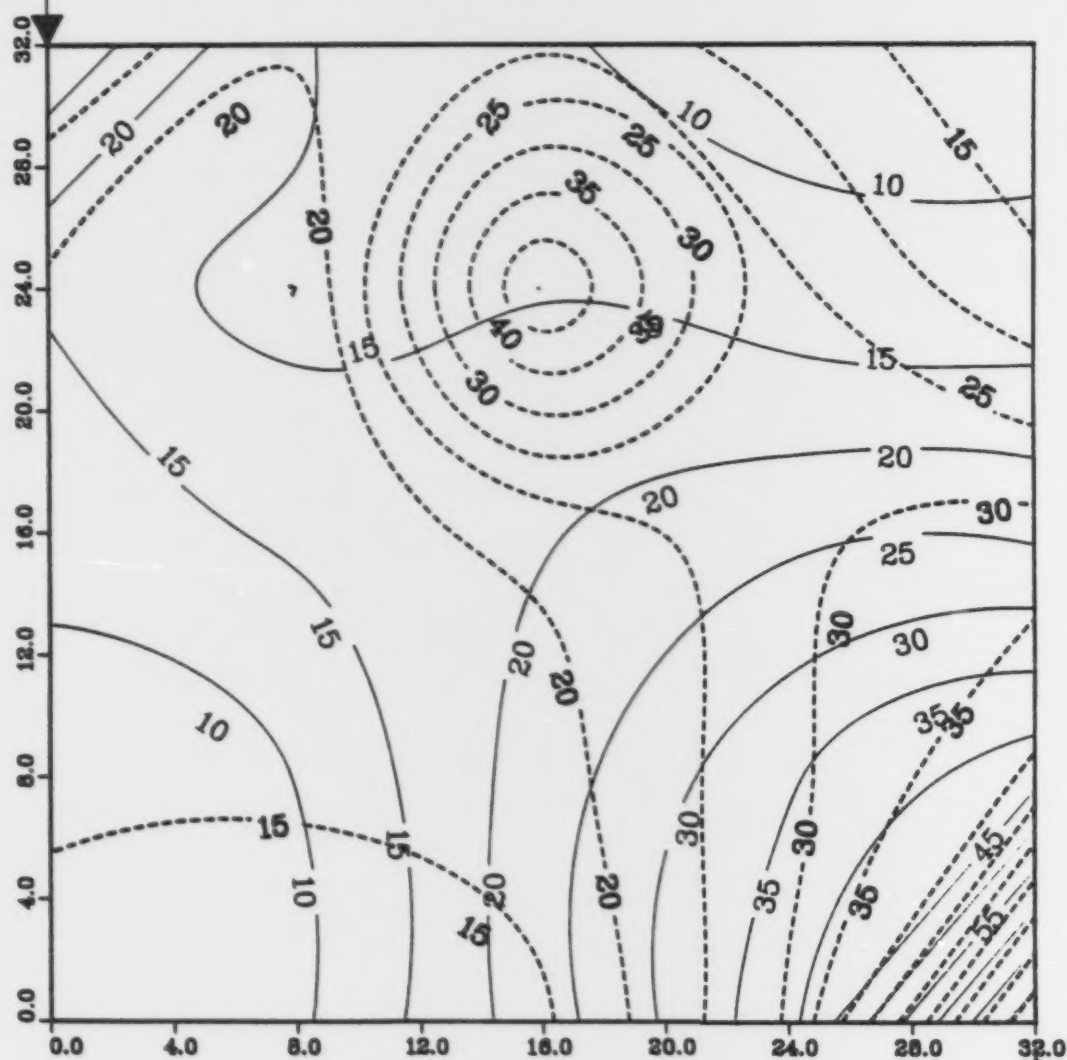


Figure A.133 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

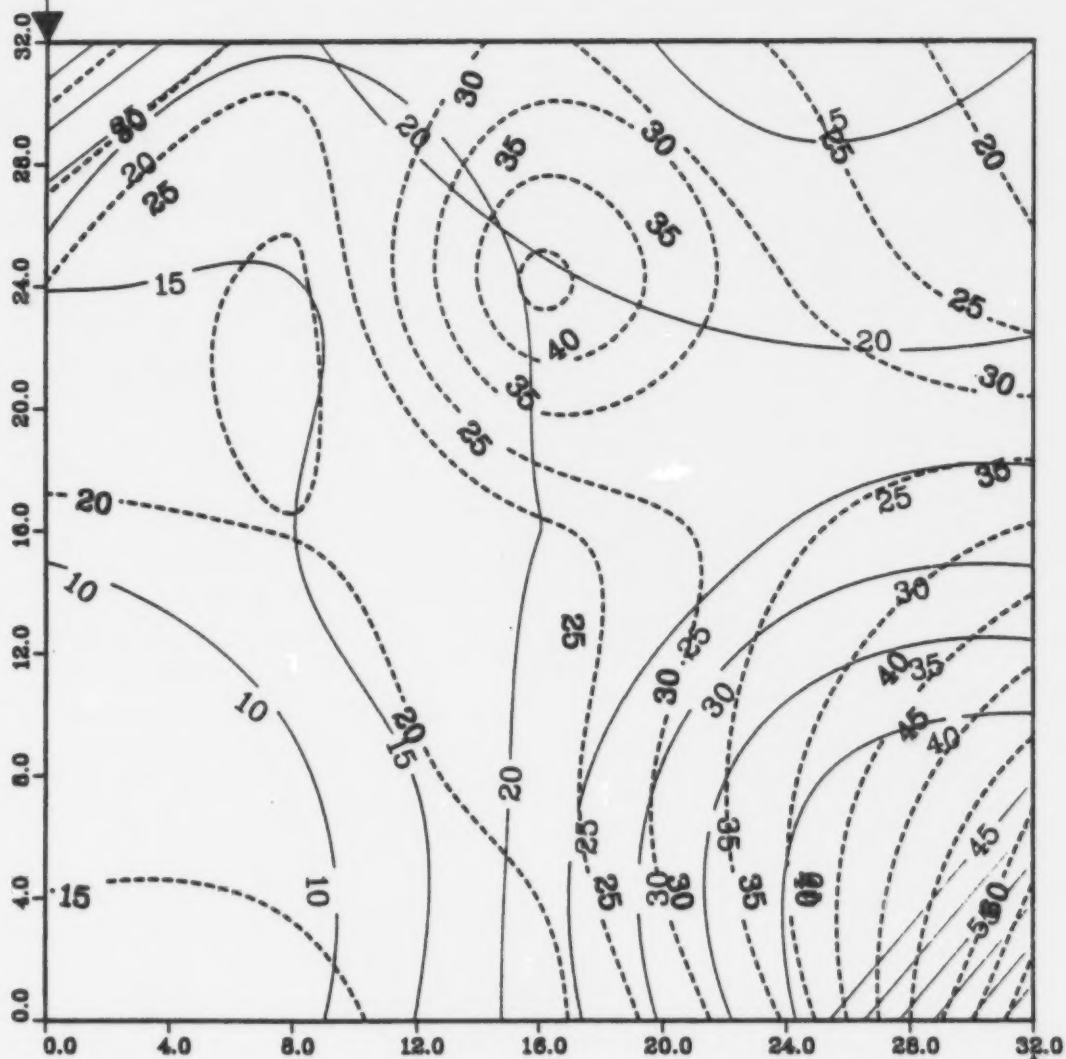
Lower Model Temperature (C)

Injection Well

Figure A.134 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.135 : Run 50
Solvent-Steamflood in E.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

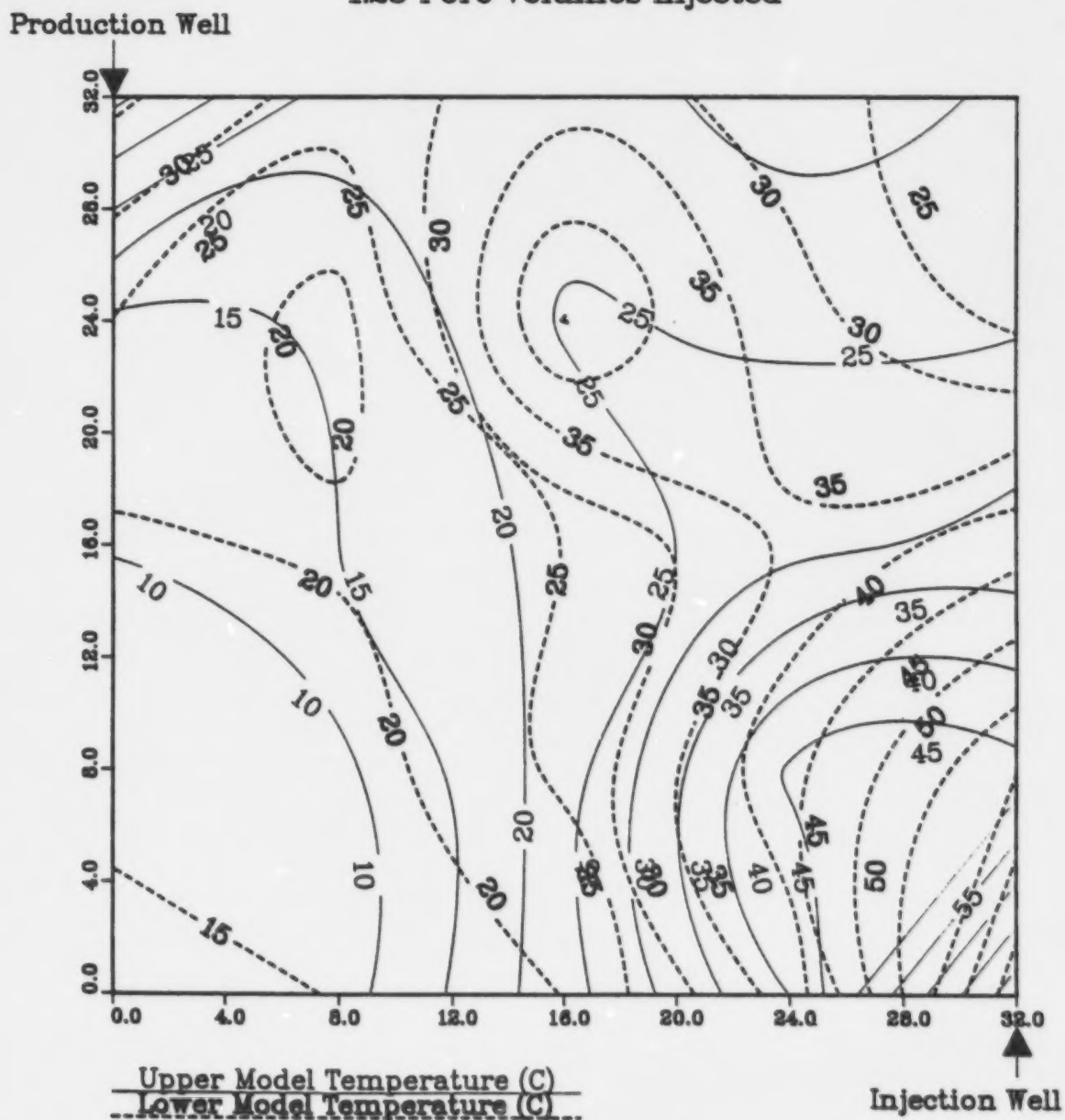


Figure A.136 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

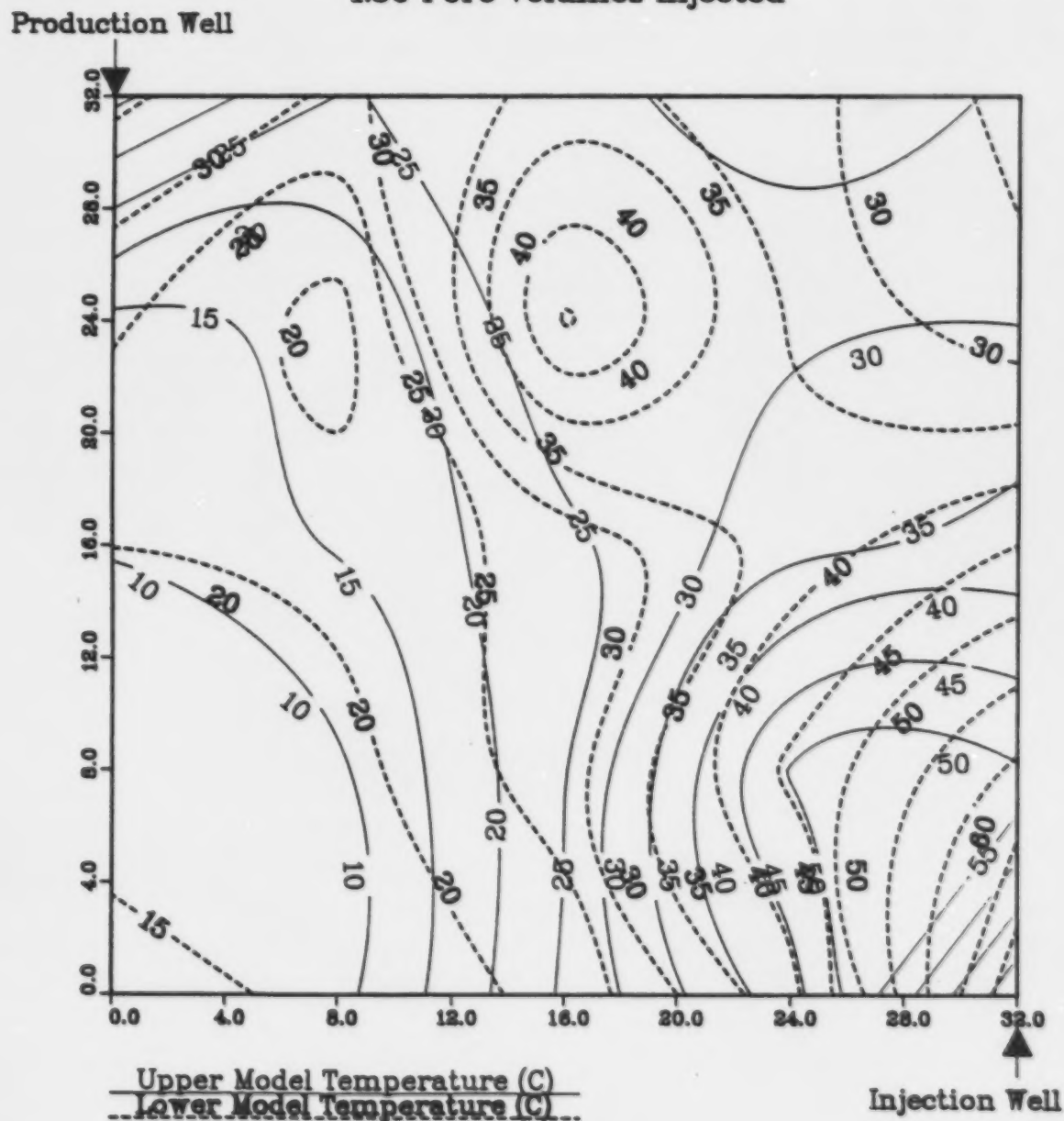
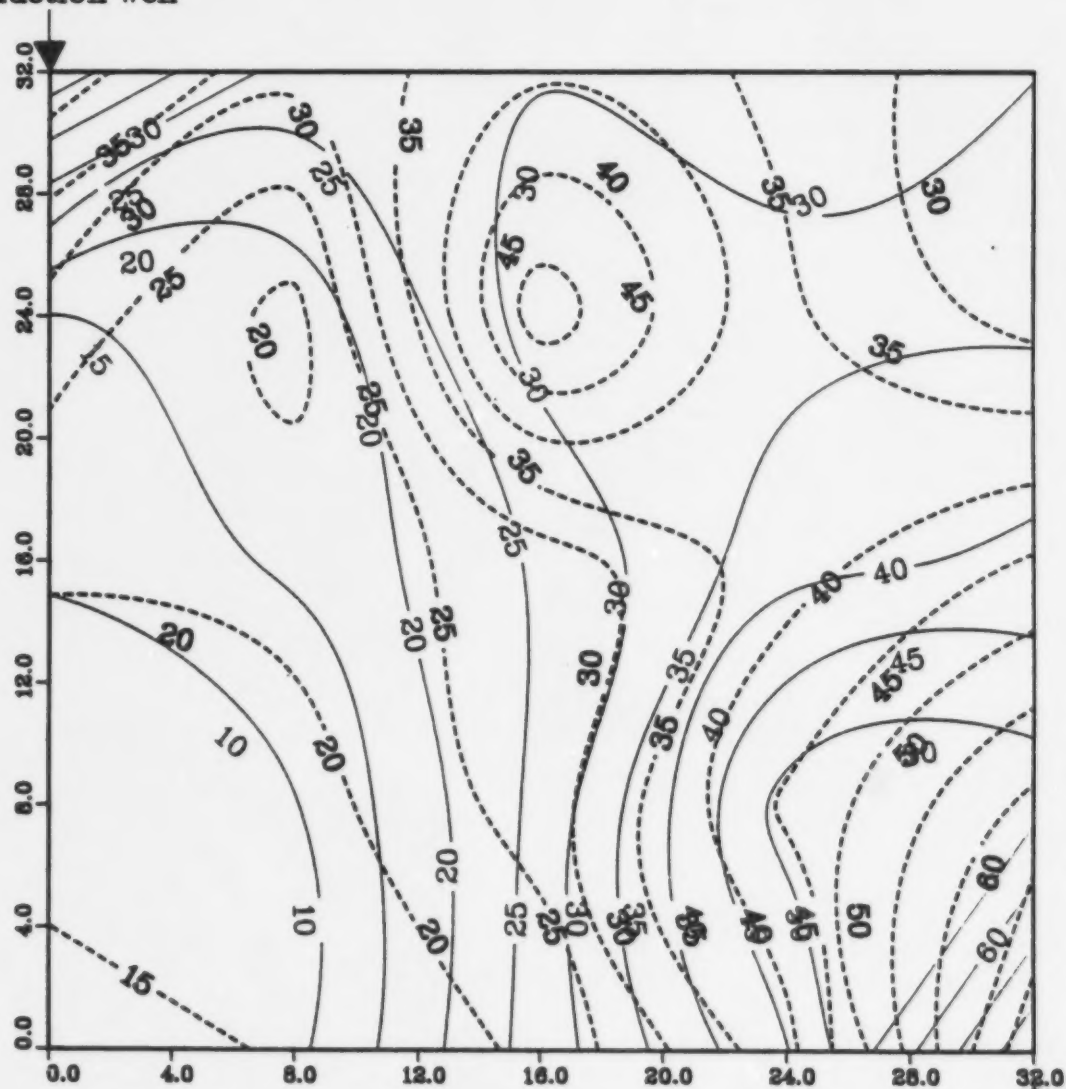


Figure A.137 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.138 : Run 50
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

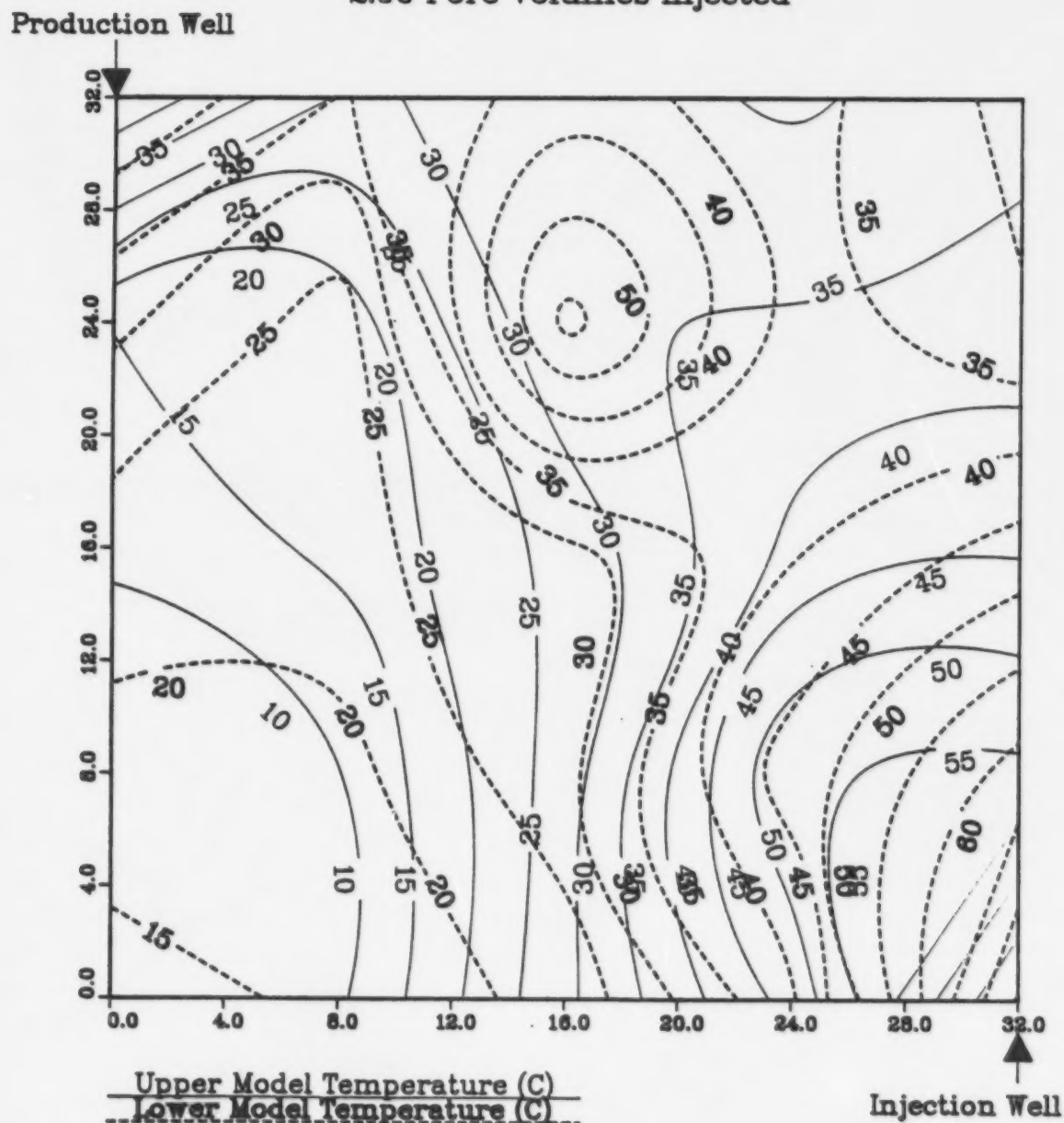


**Figure A.139 :Run 50 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

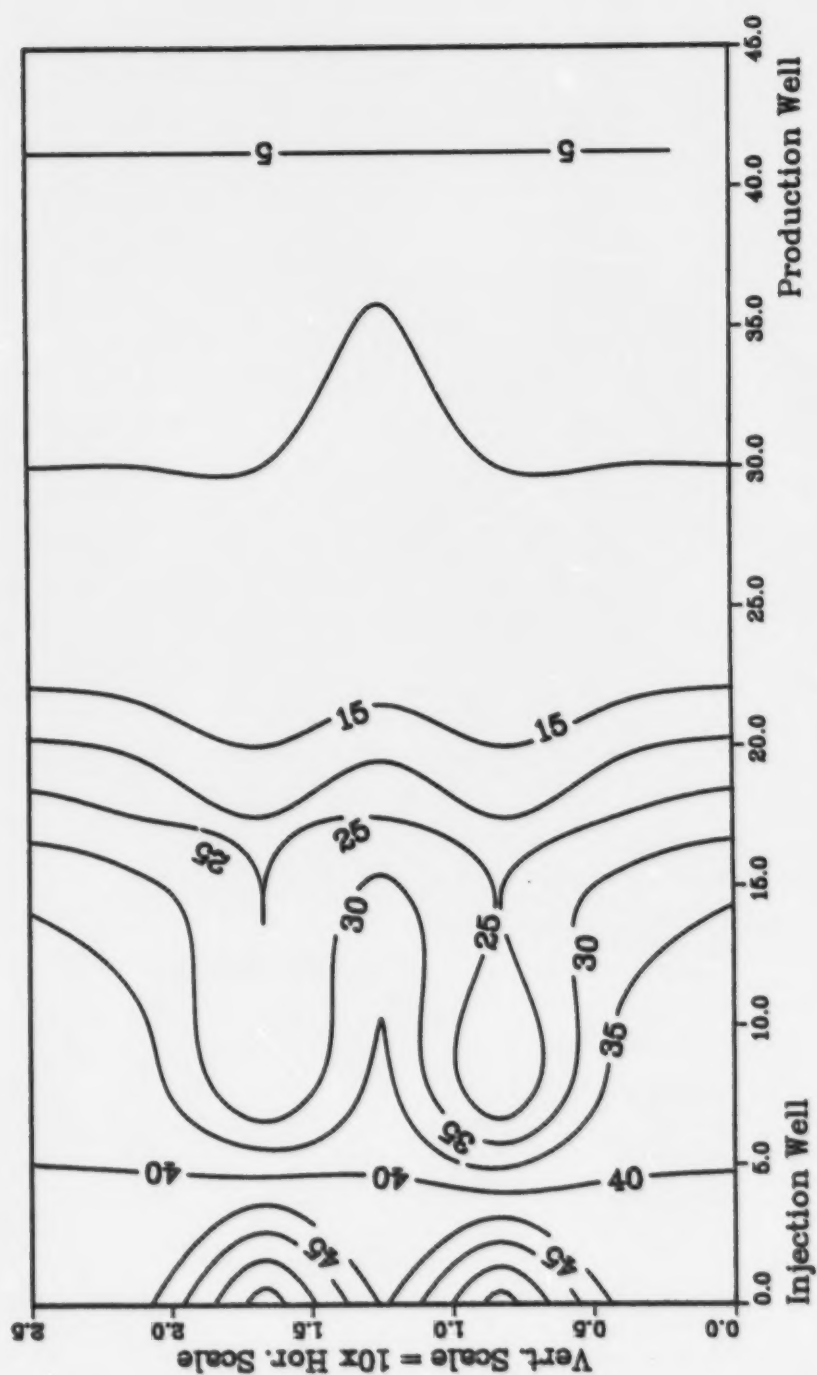


**Figure A.140 :Run 50 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

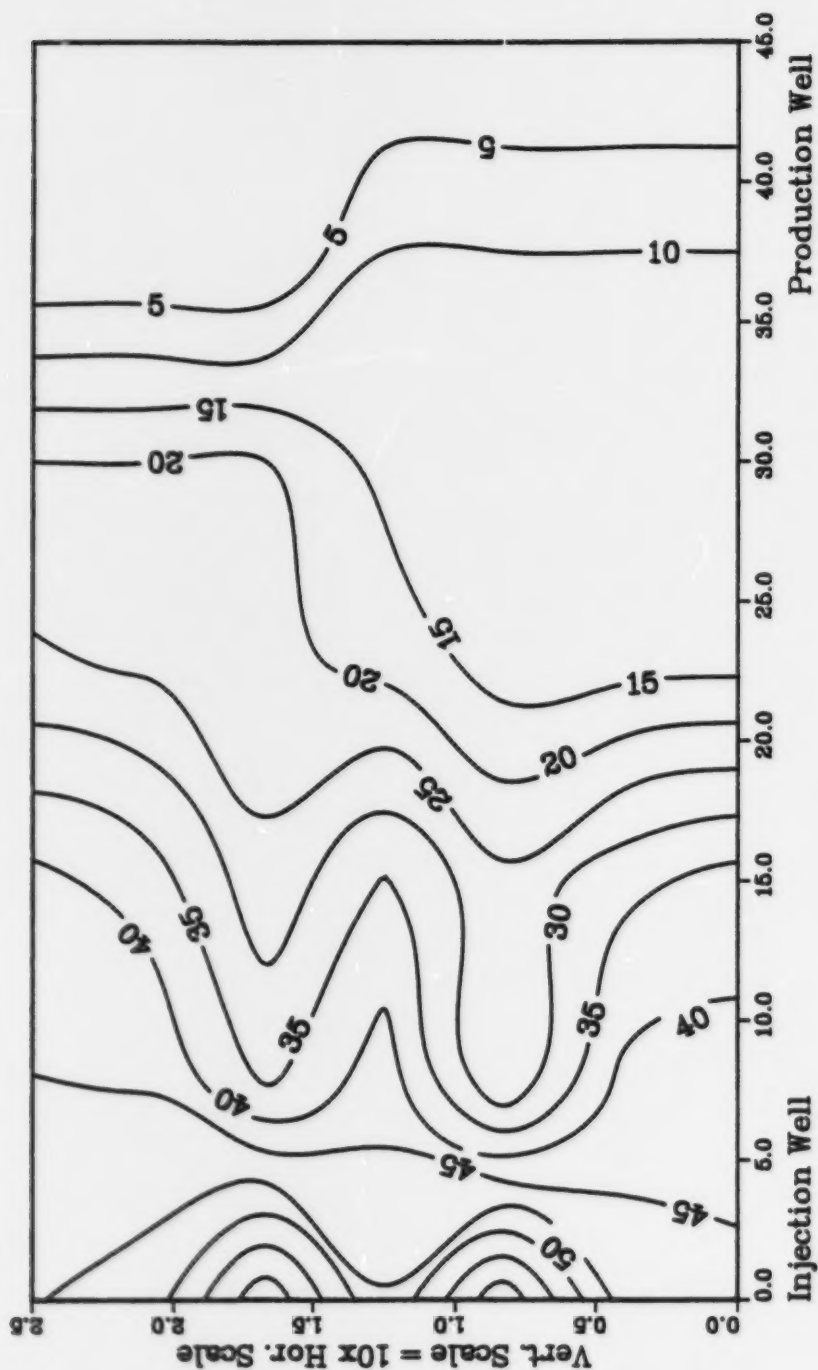


**Figure A.141 :Run 50 Temp Profile
Injector to Producer Cross-Section**

0.75 Pore Volumes Injected.

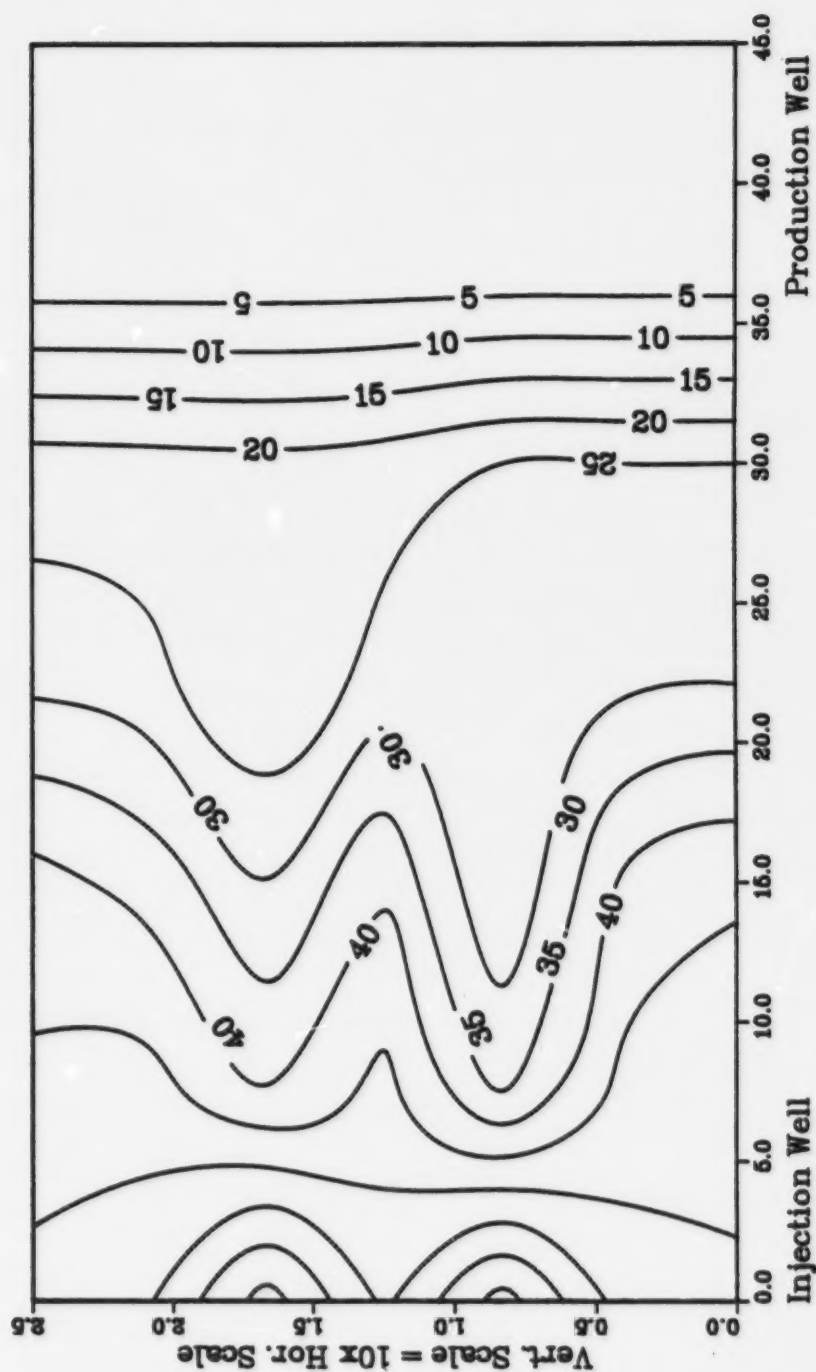


**Figure A.142 :Run 50 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

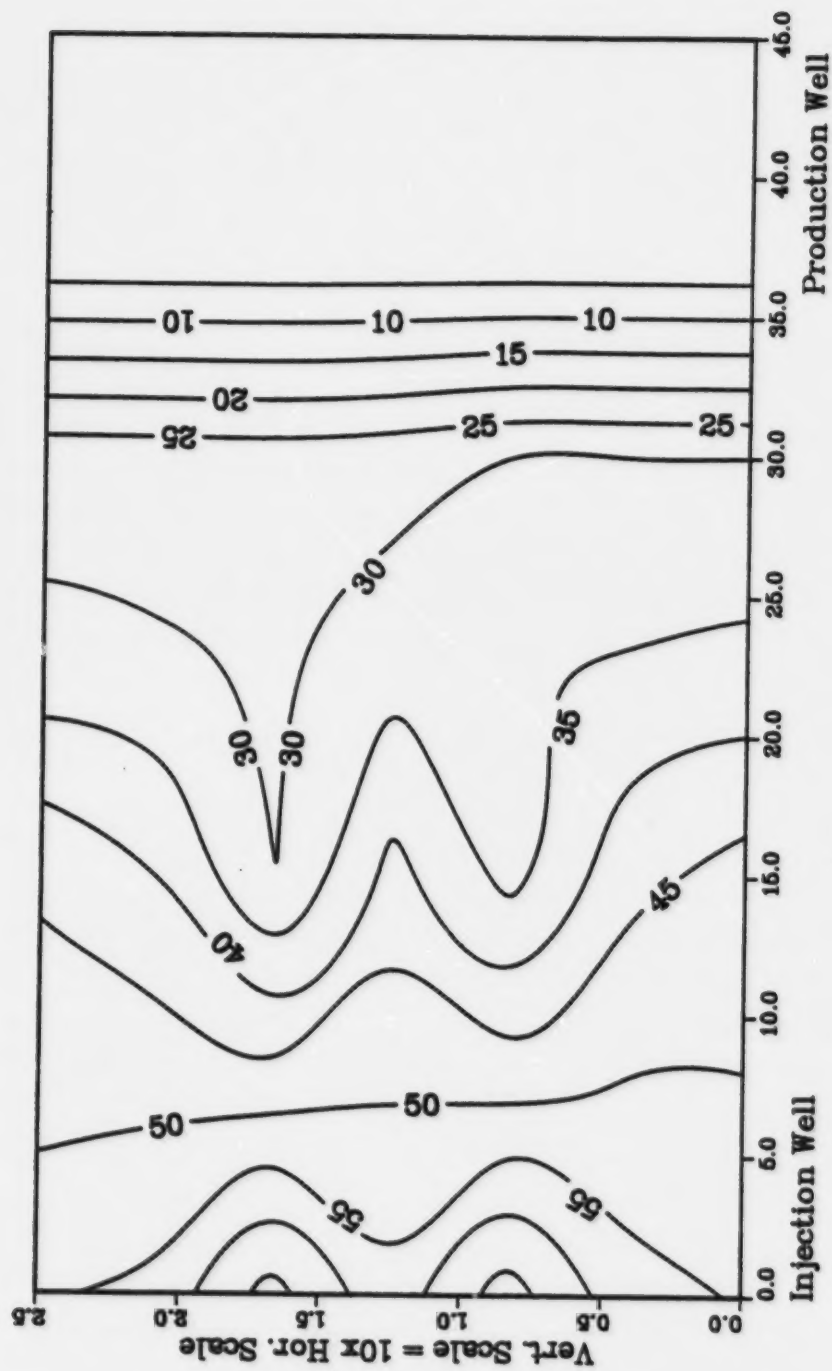
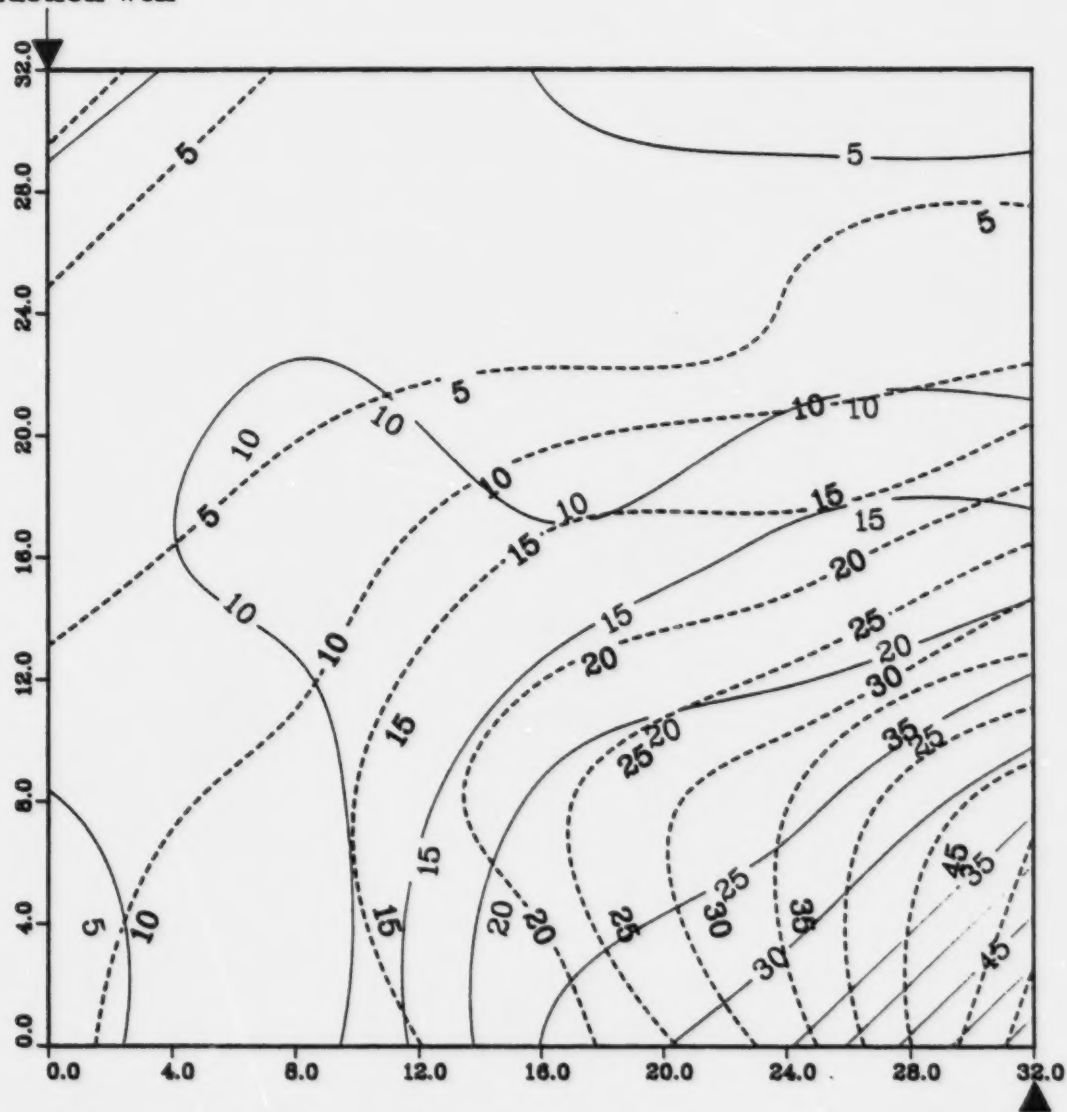


Figure A.143 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.144 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

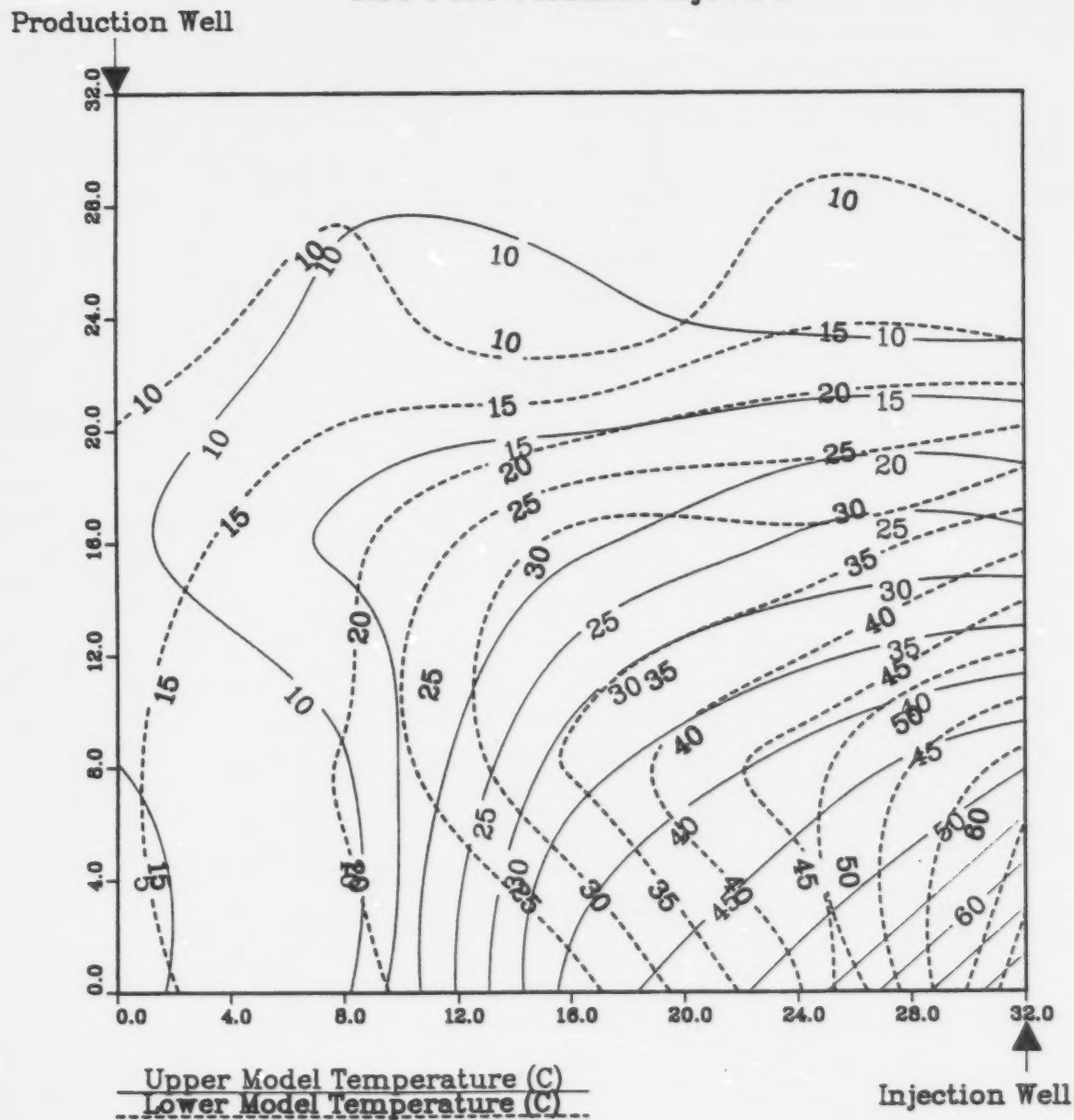


Figure A.145 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

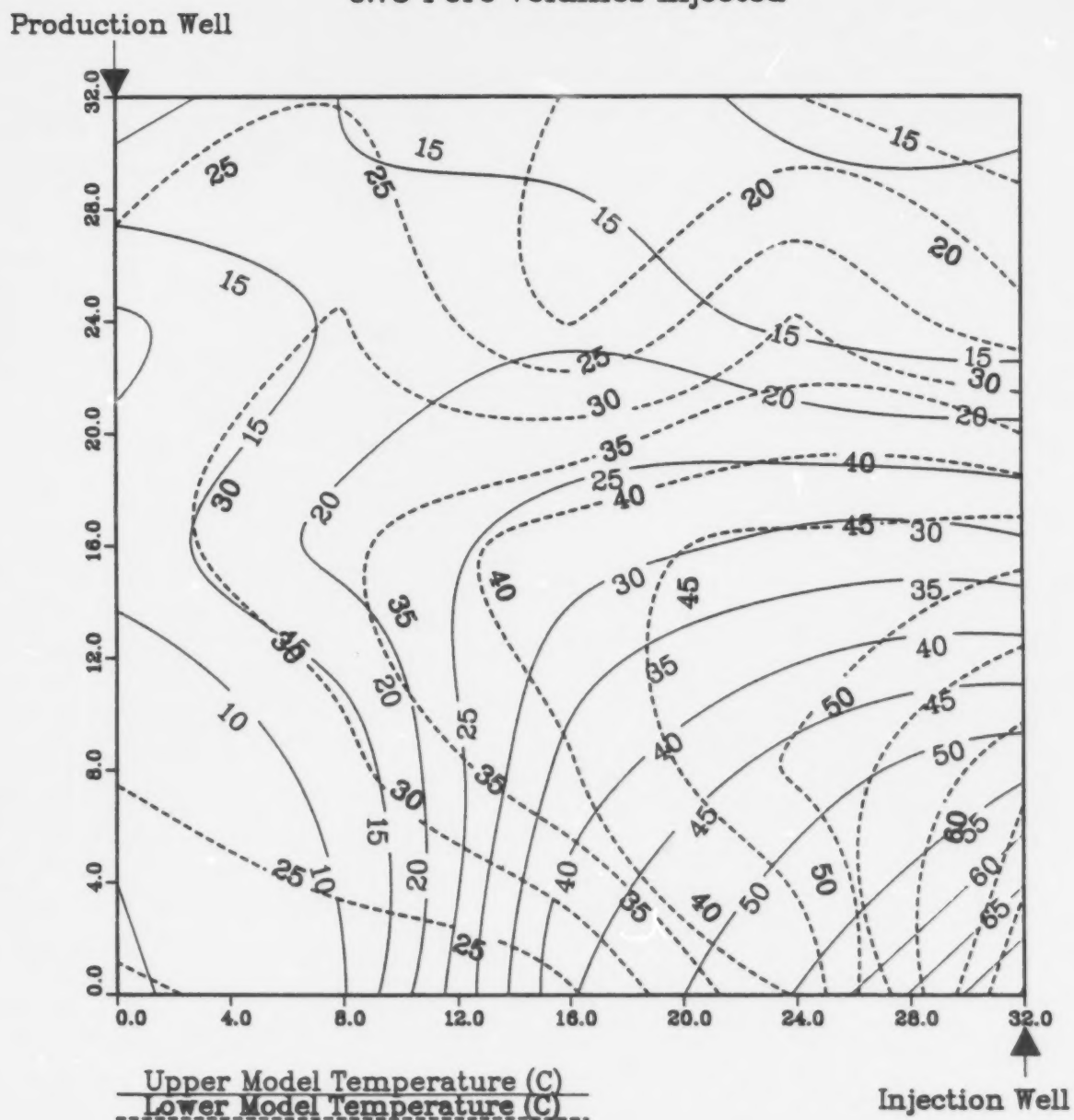
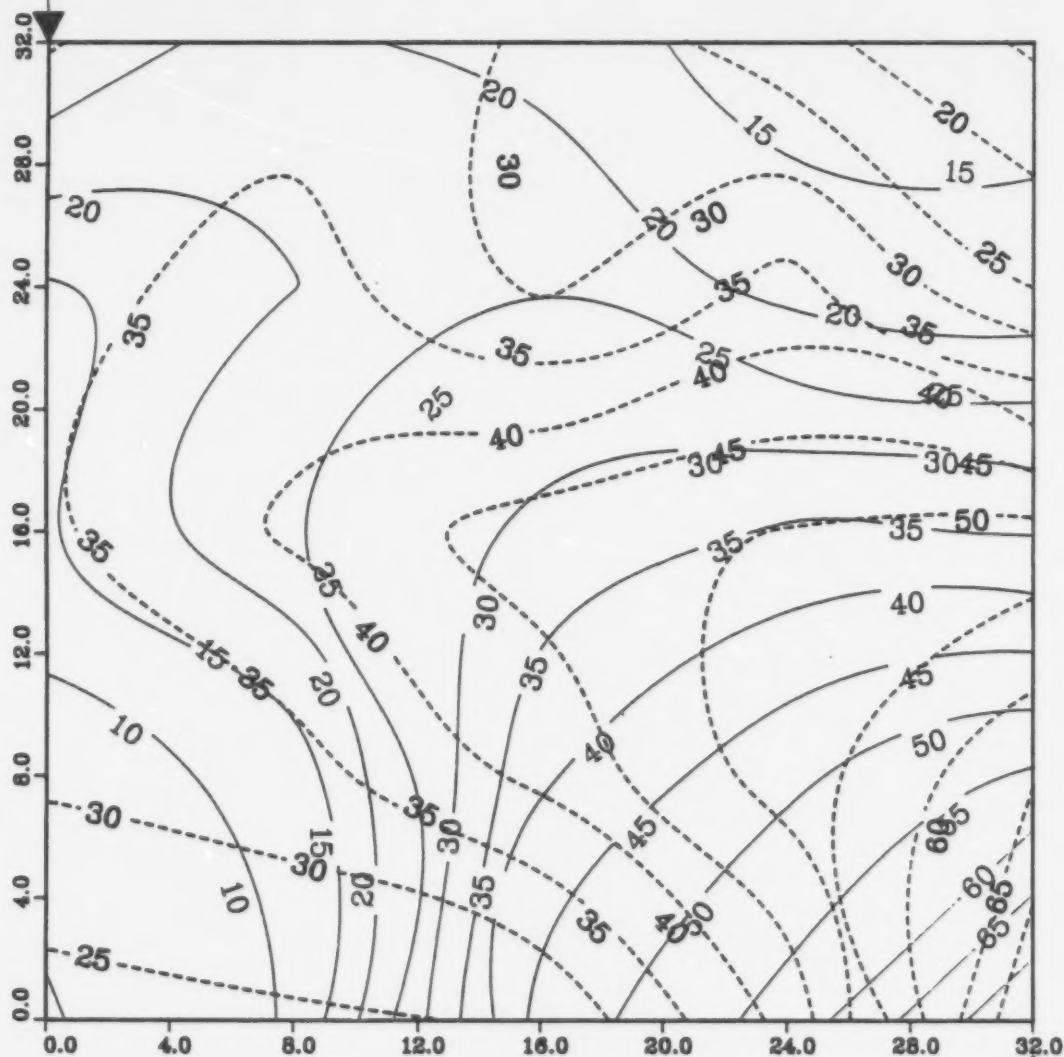


Figure A.146 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

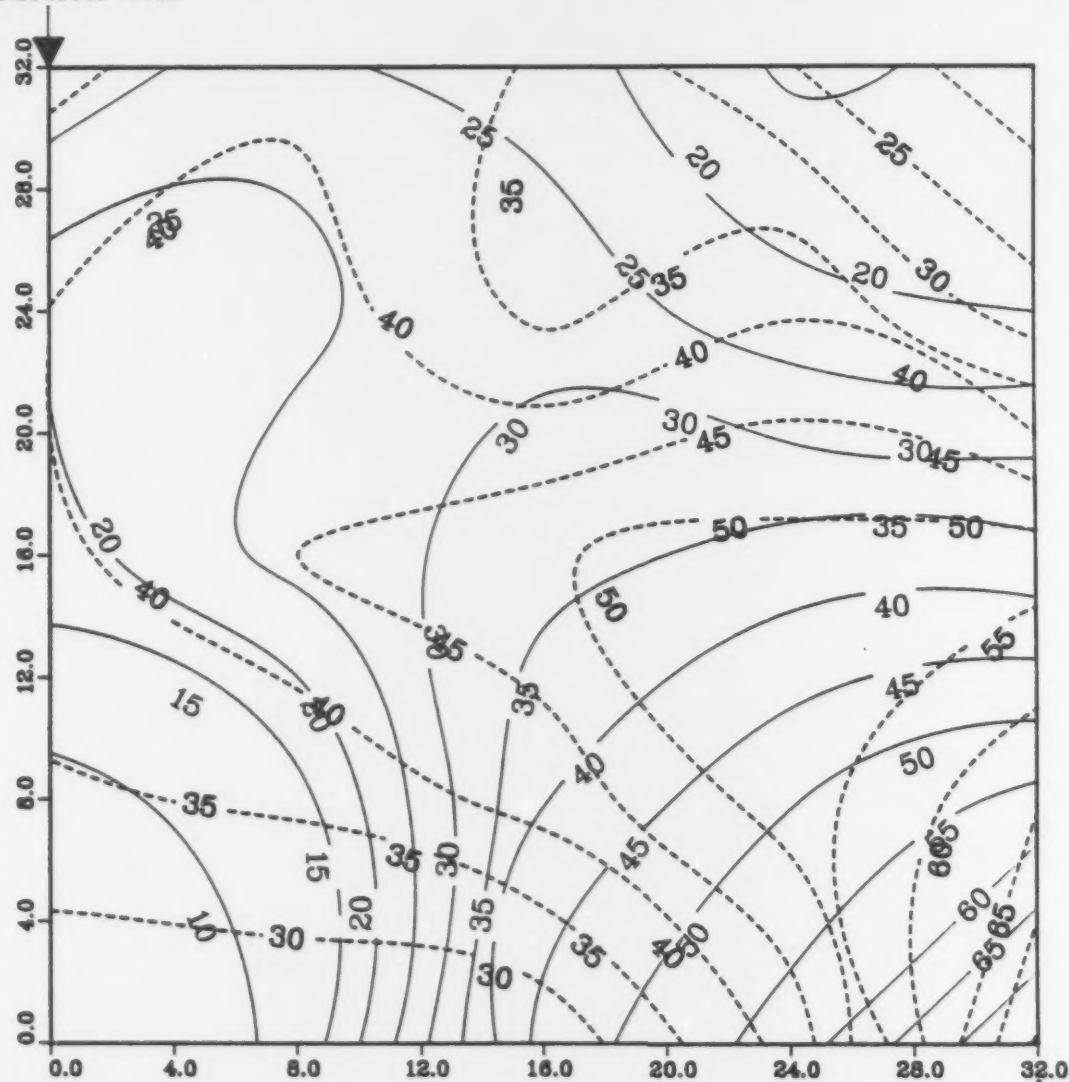
Lower Model Temperature (C)

Injection Well

Figure A.147 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.148 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

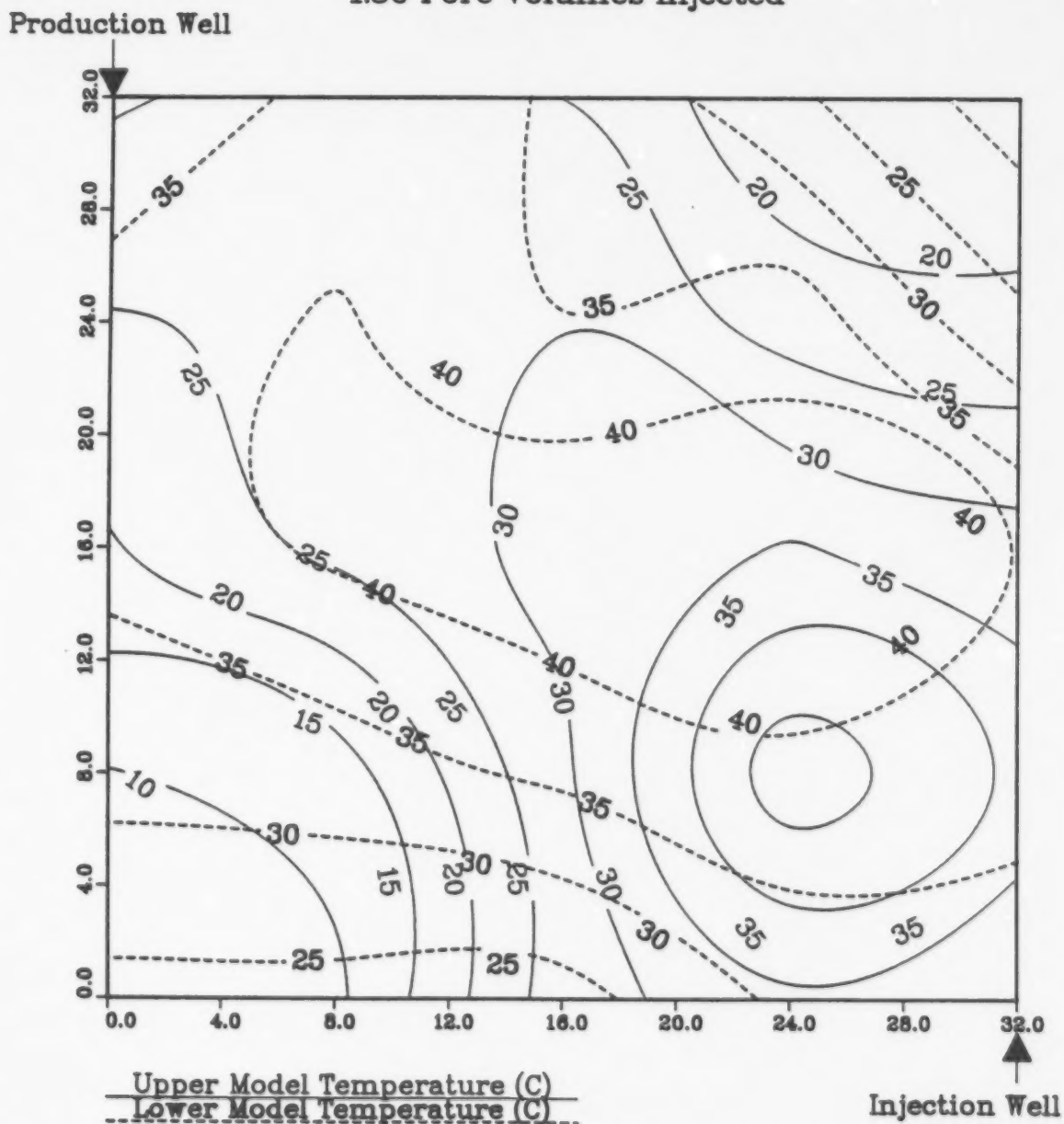


Figure A.149 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

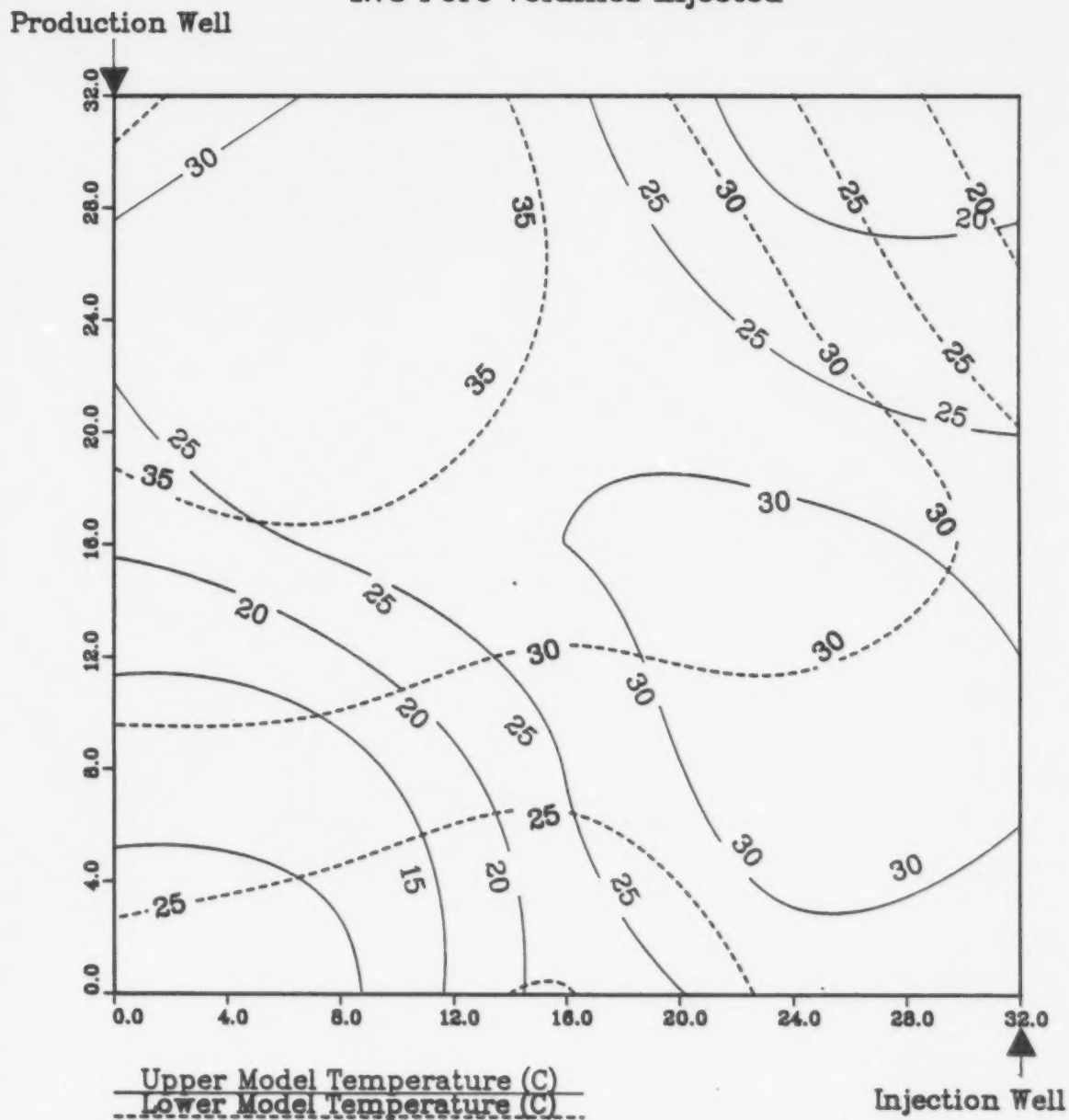
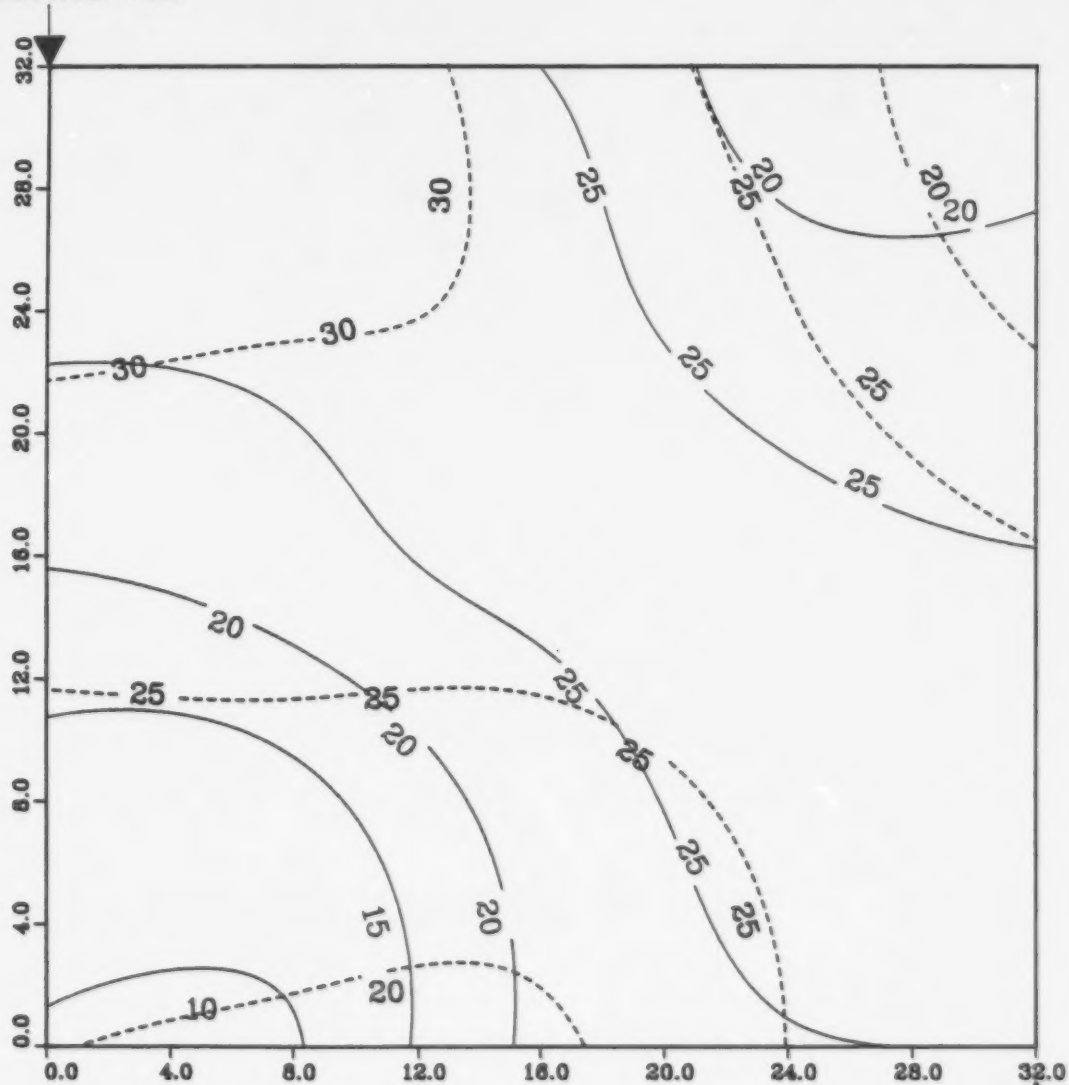


Figure A.150 : Run 51
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.151 :Run 51 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

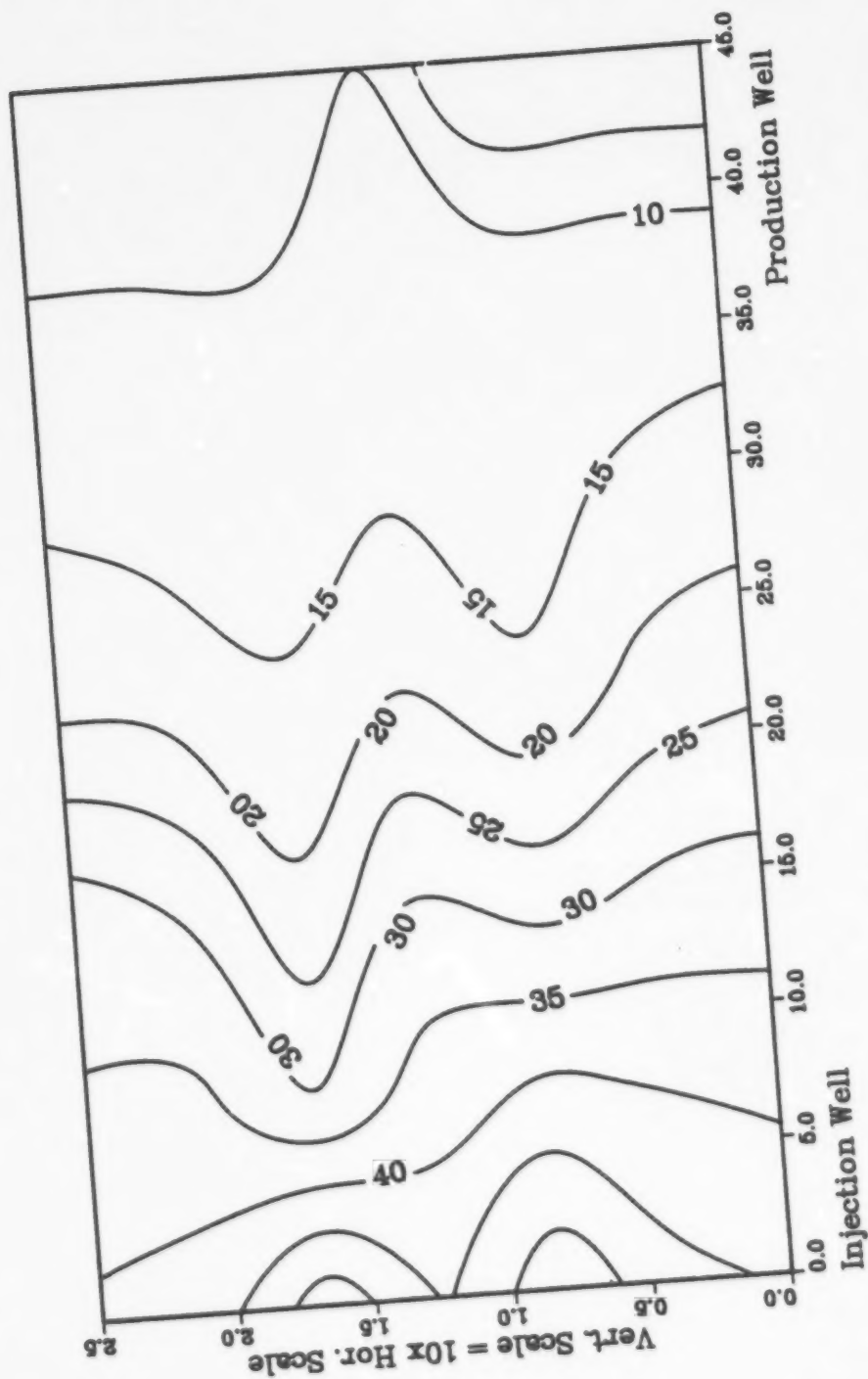


**Figure A.152 :Run 51 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

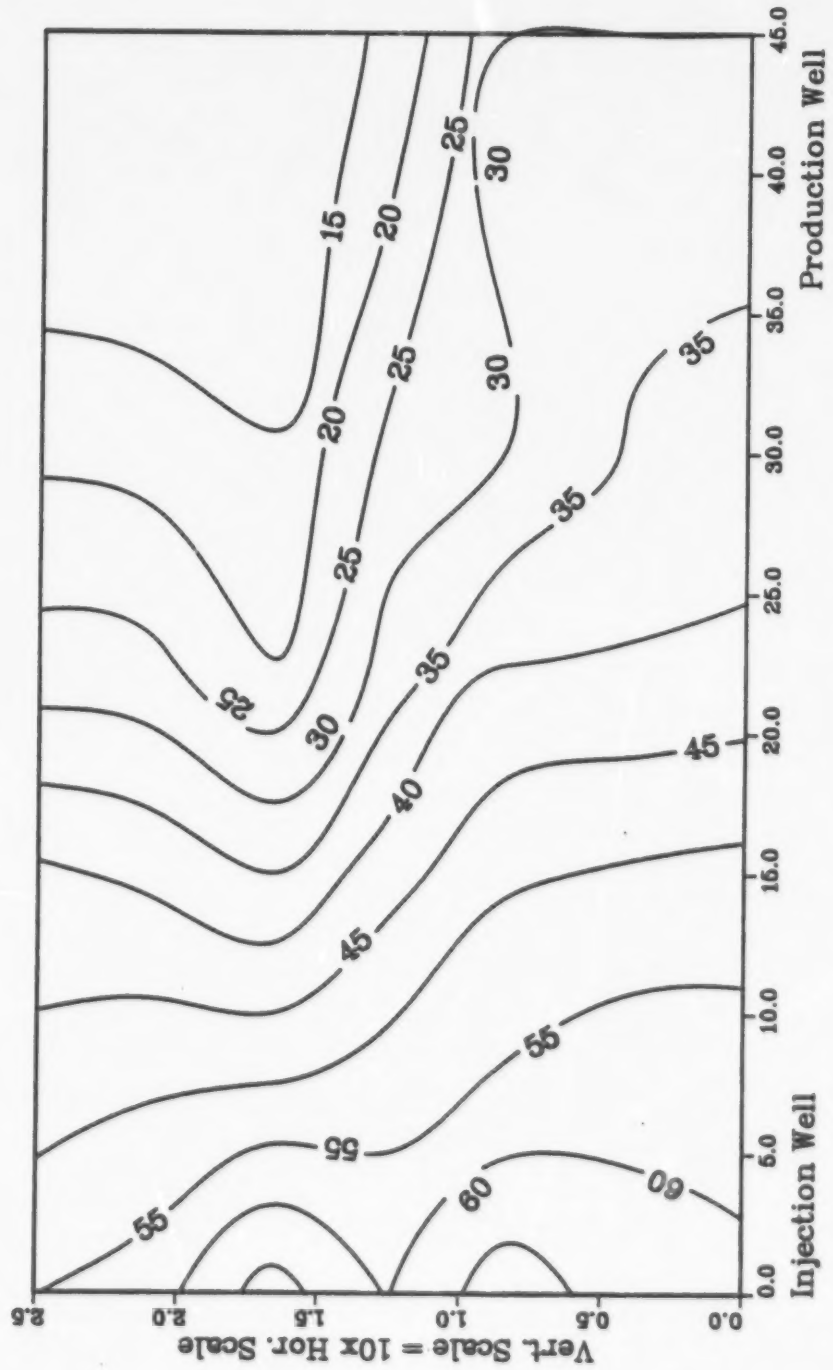


**Figure A.153 :Run 51 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

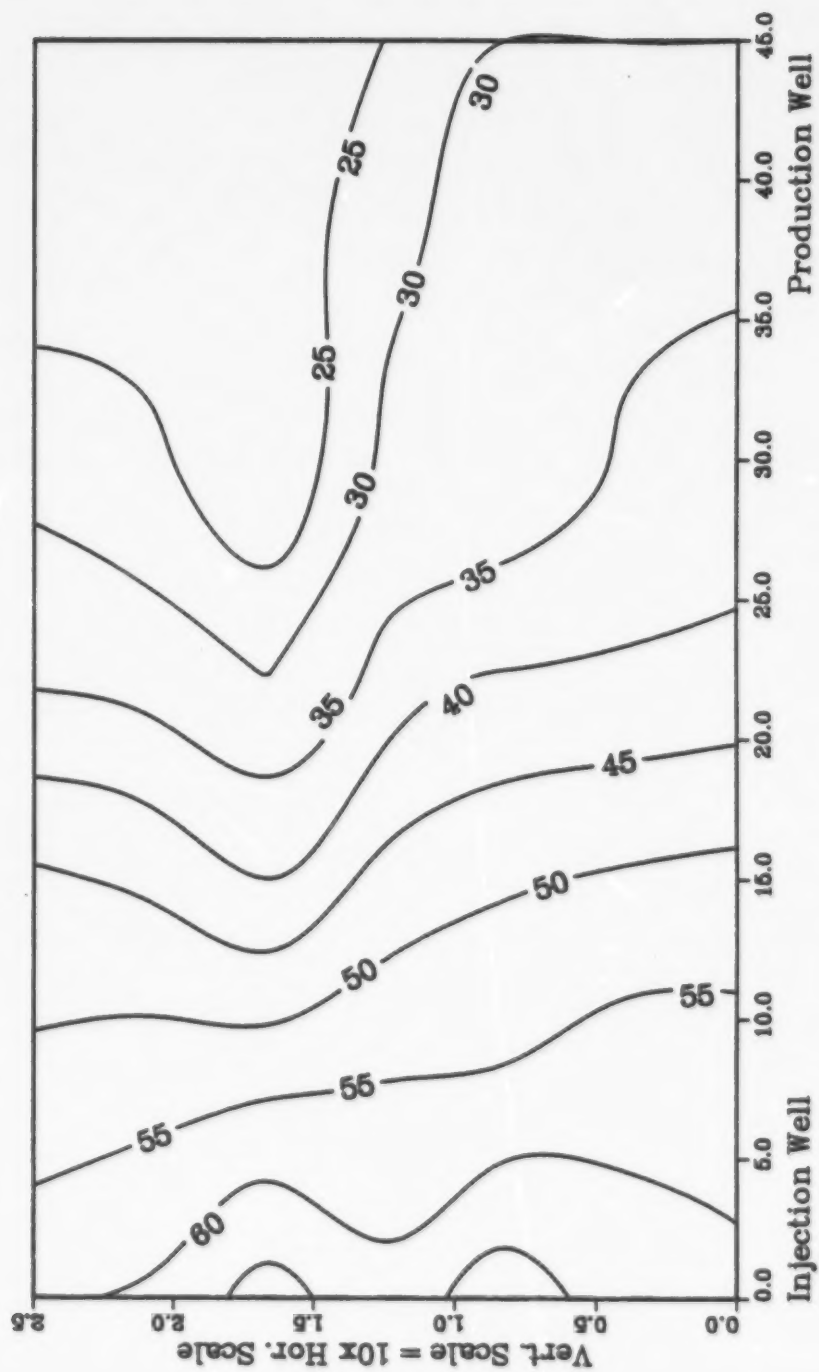


**Figure A.154 :Run 51 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

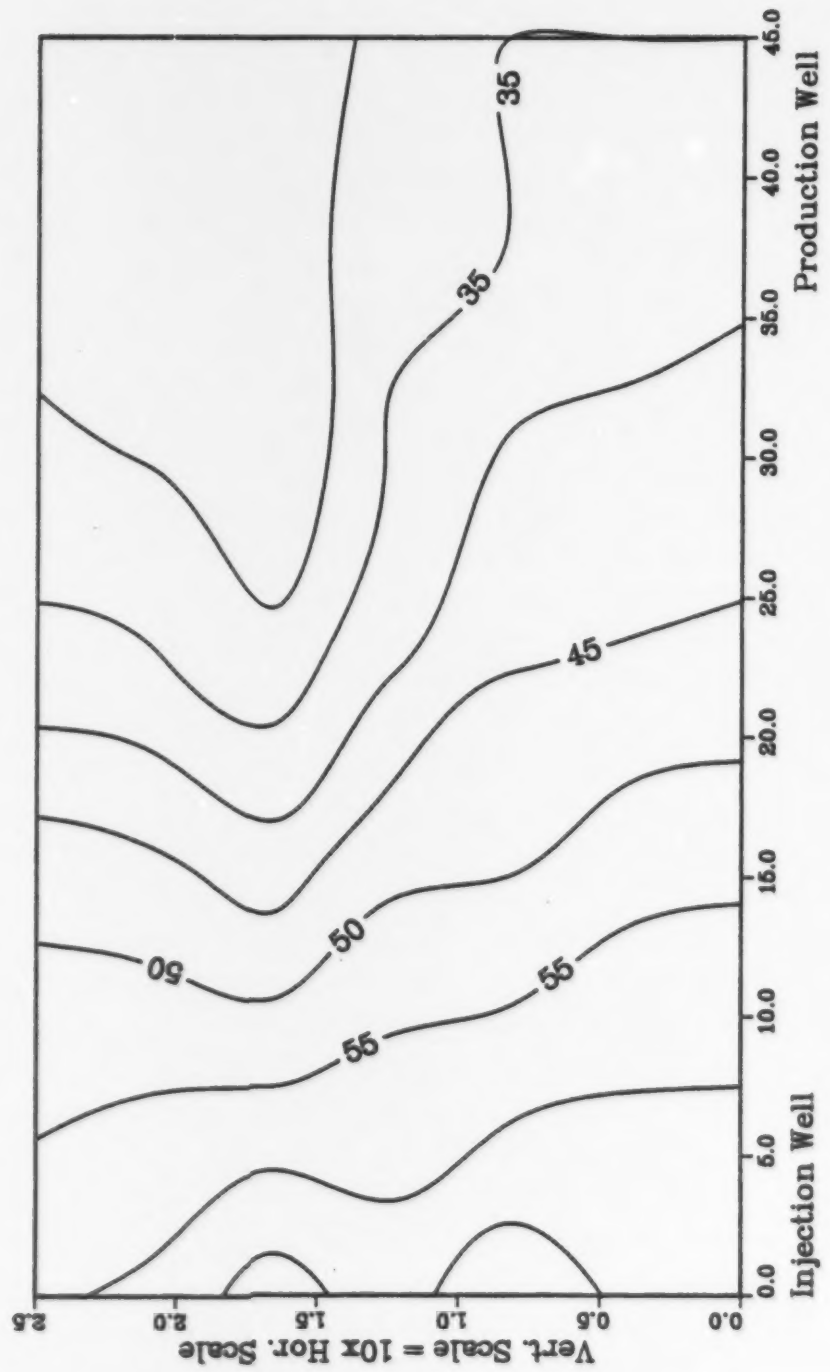


Figure A.155 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

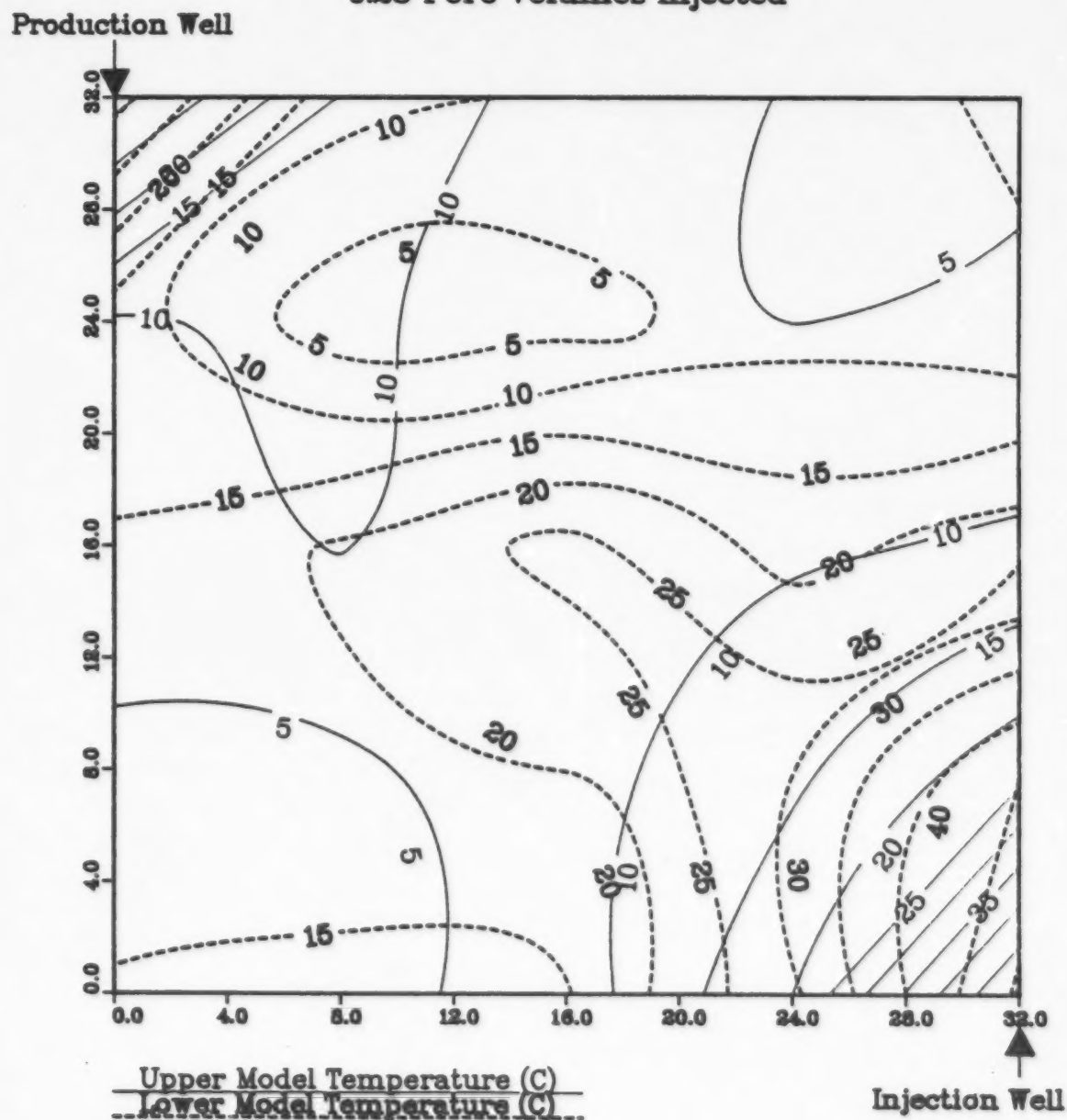
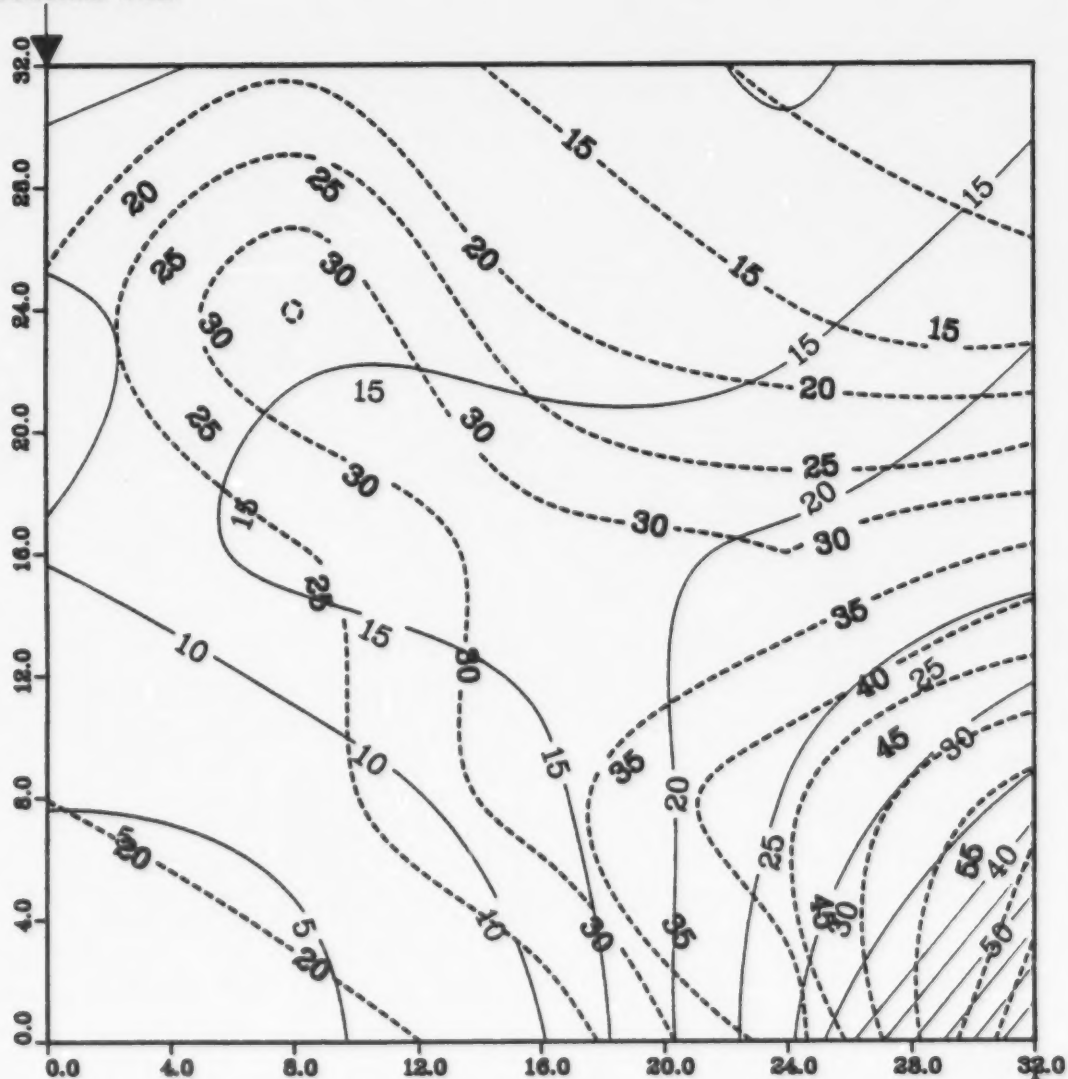


Figure A.156 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



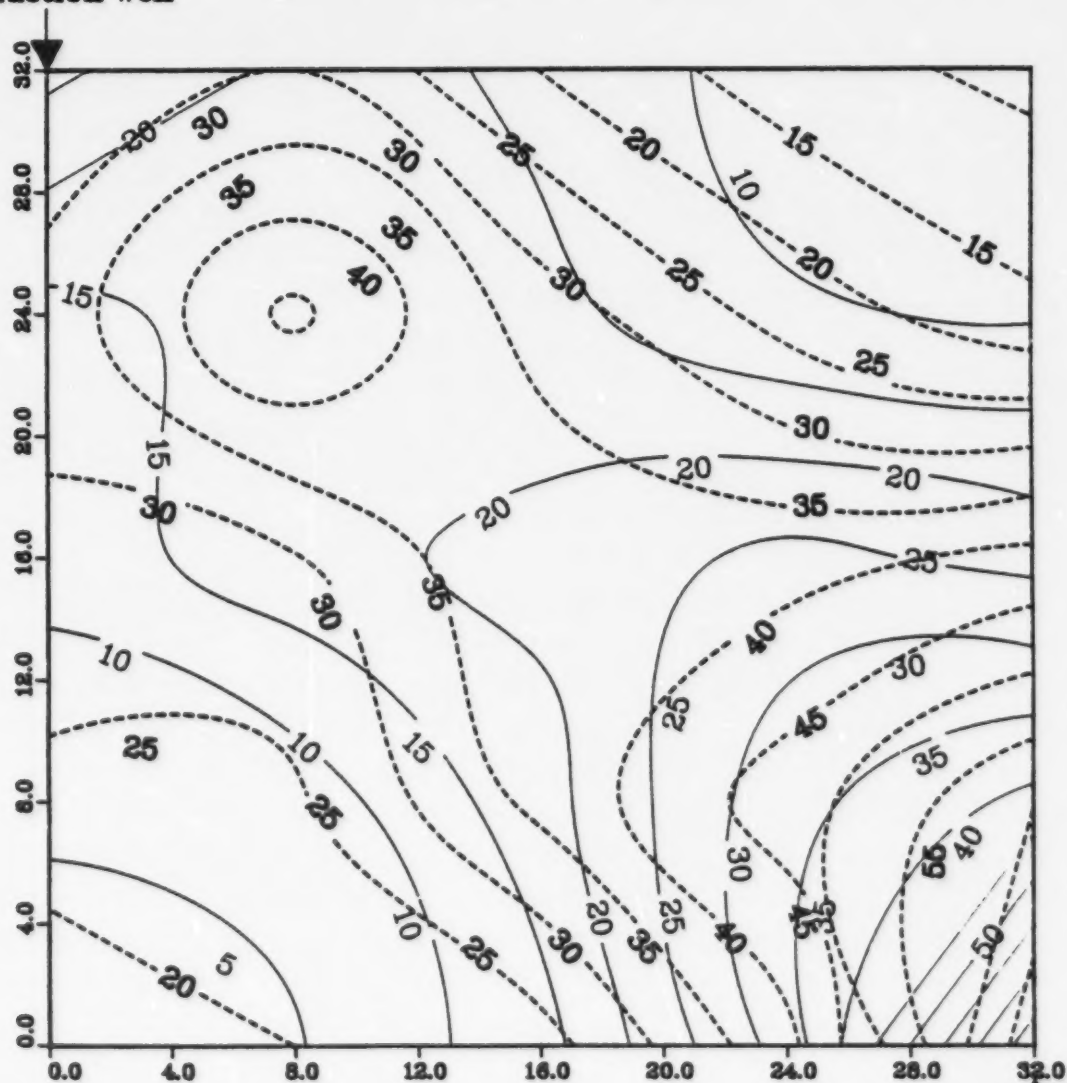
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A157 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



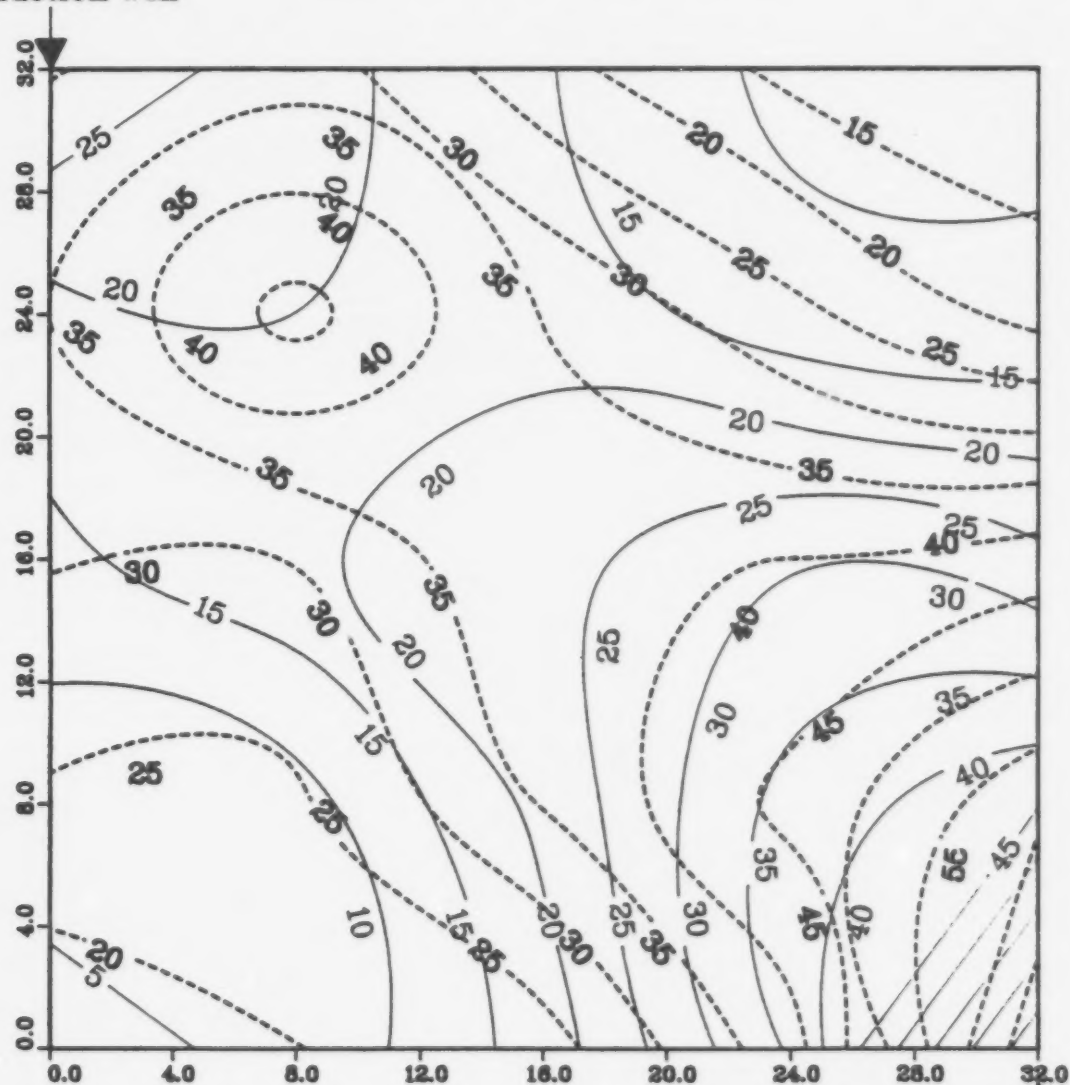
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.158 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

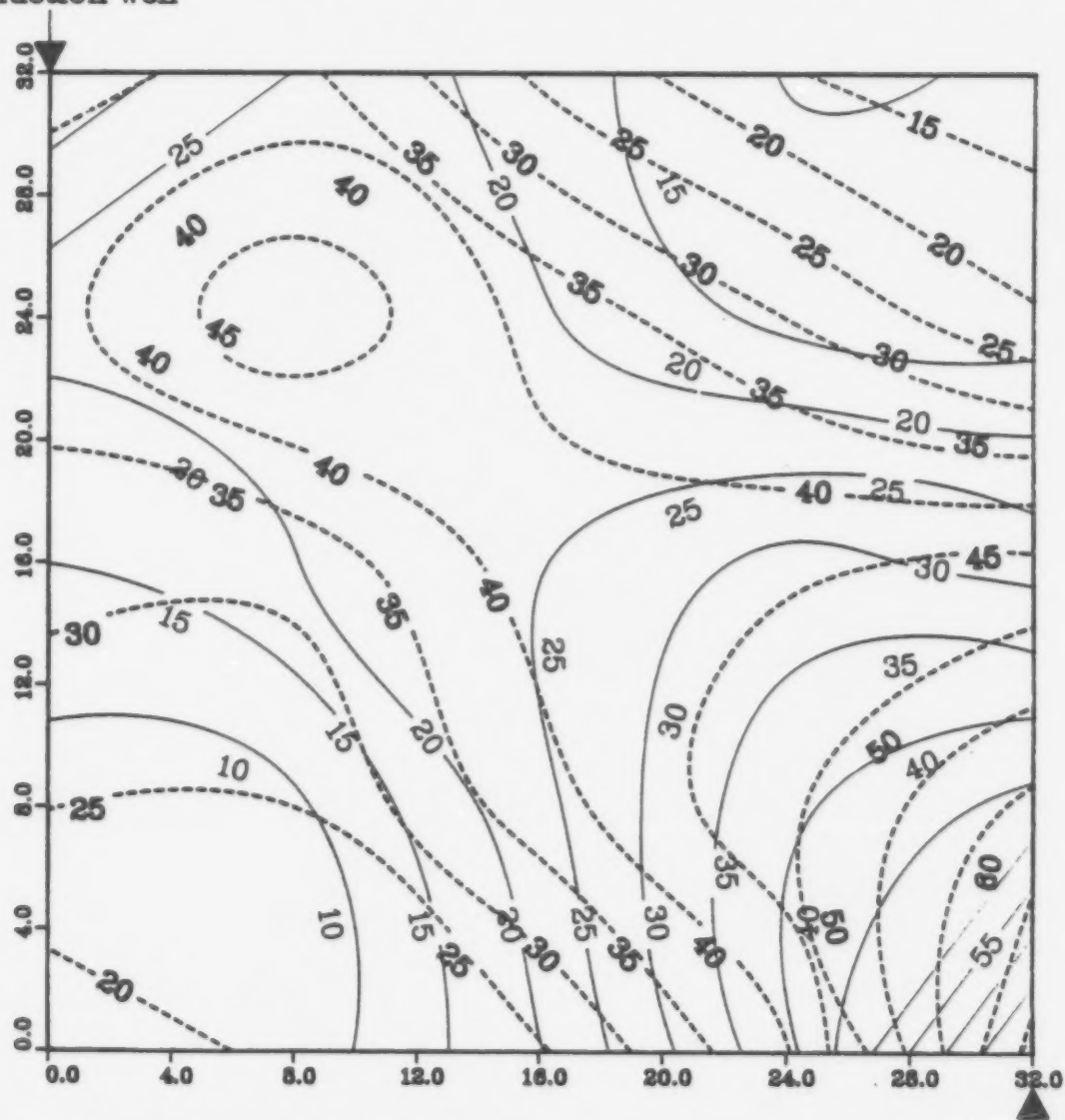
Lower Model Temperature (C)

Injection Well

Figure A.159 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.160 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

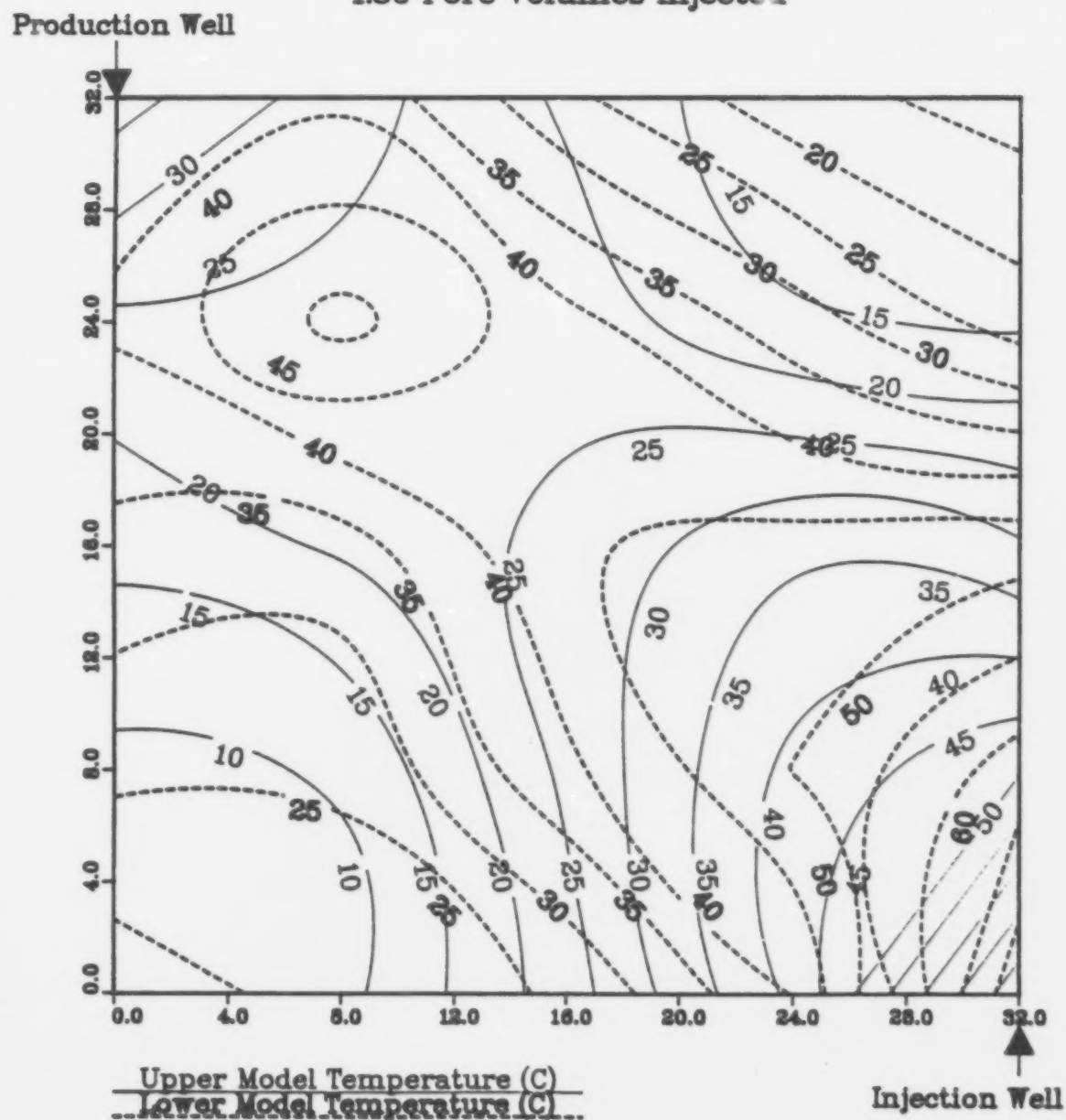
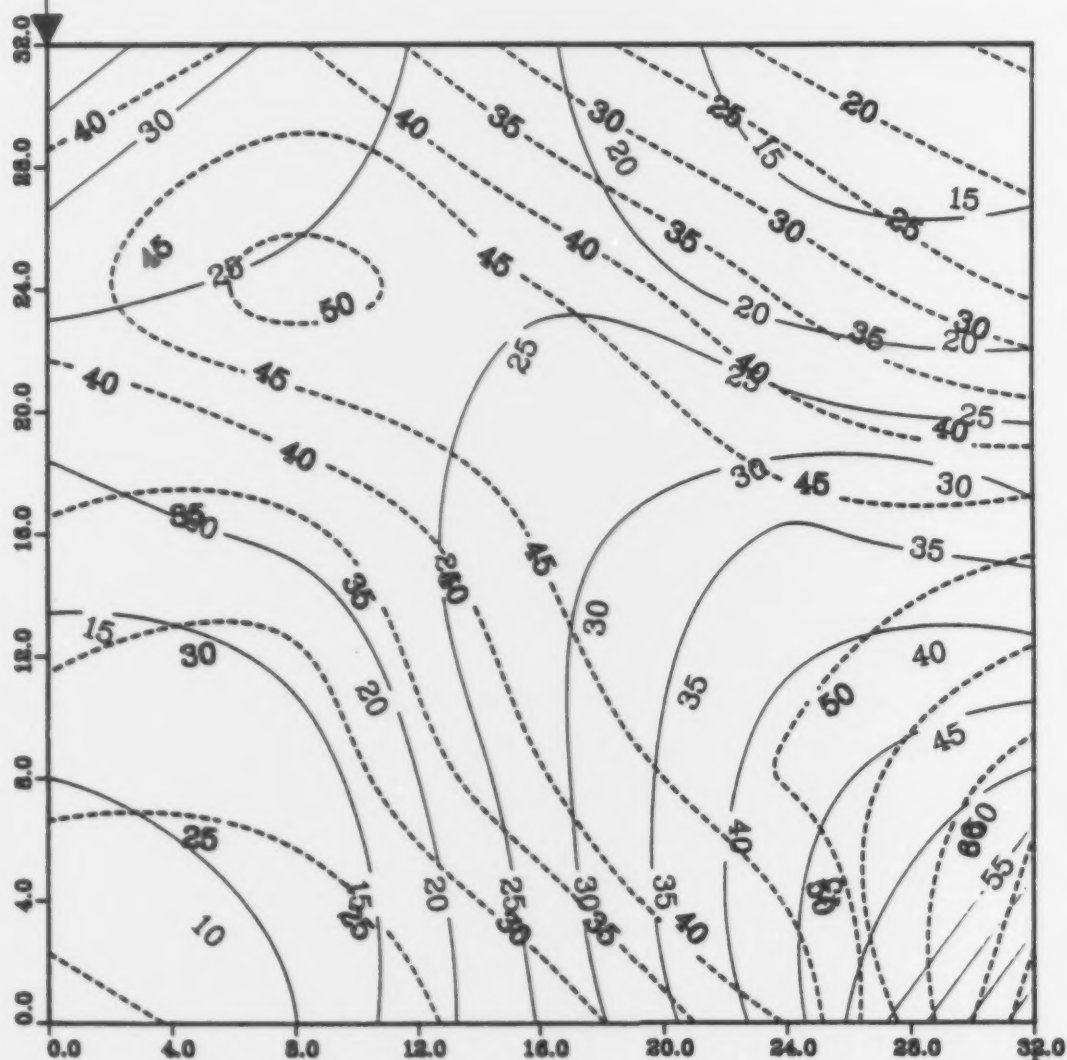


Figure A.161 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



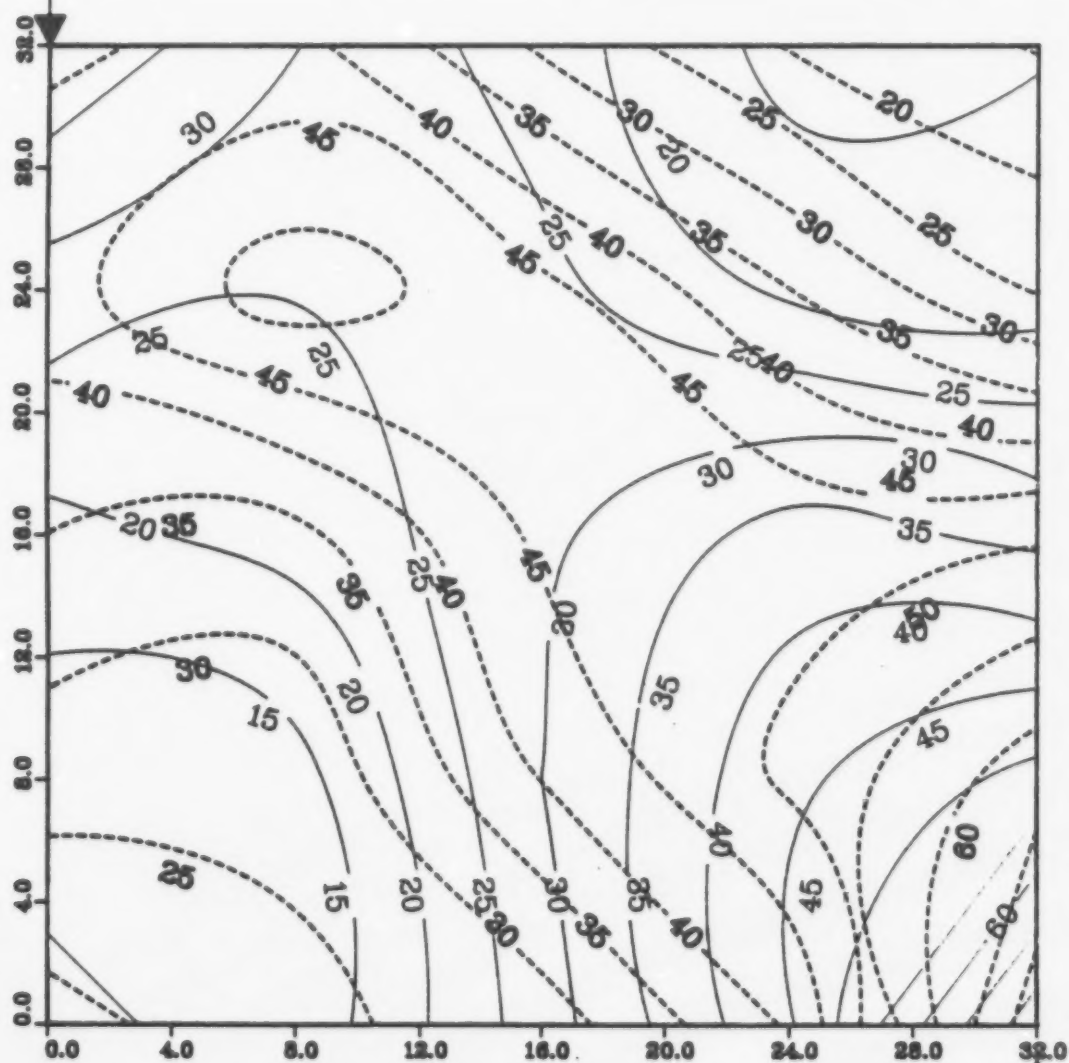
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.162 : Run 53
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.163 :Run 53 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

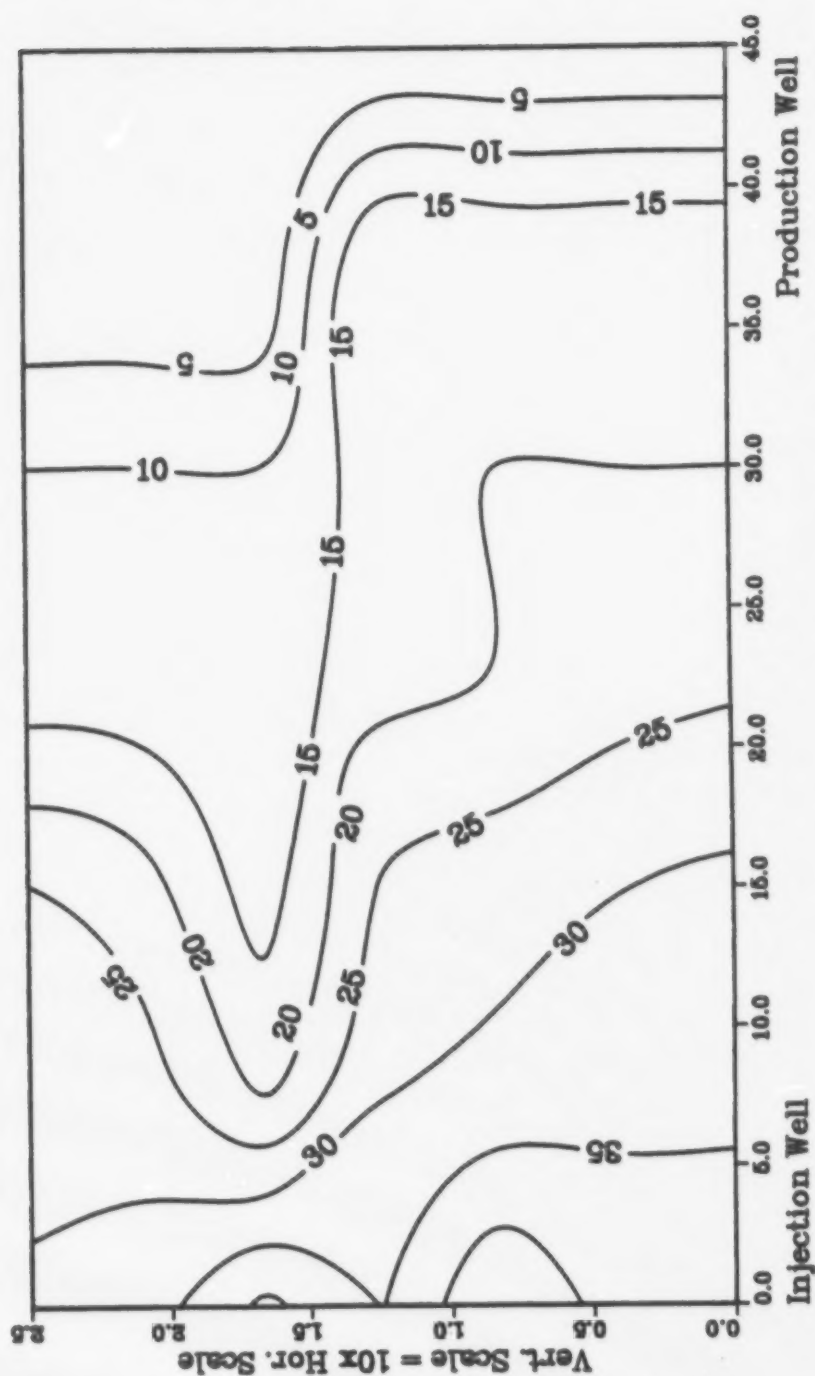


**Figure A.164 :Run 53 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

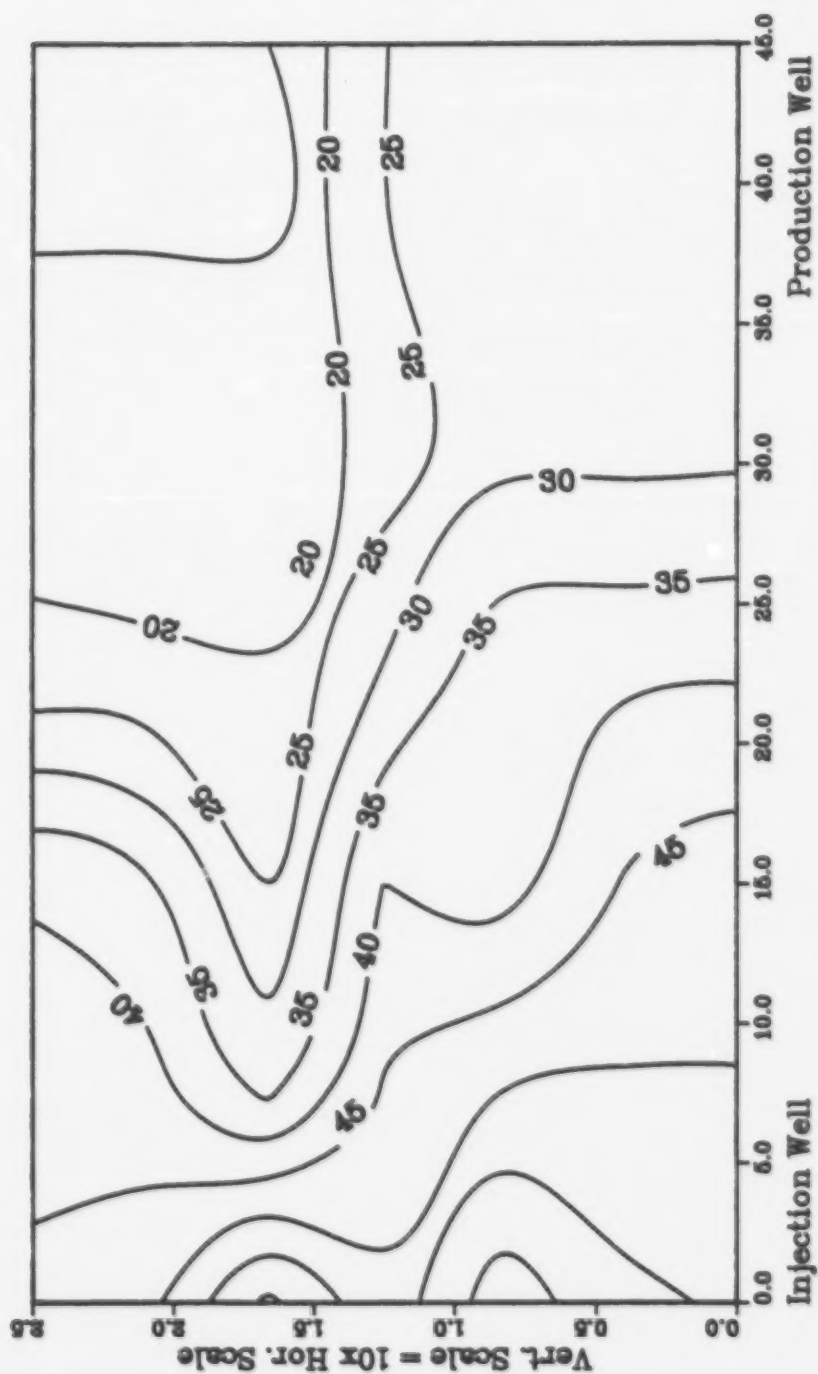


**Figure A.165 :Run 53 Temp Profile
Injector to Producer Cross-Section
0.76 Pore Volumes Injected.**

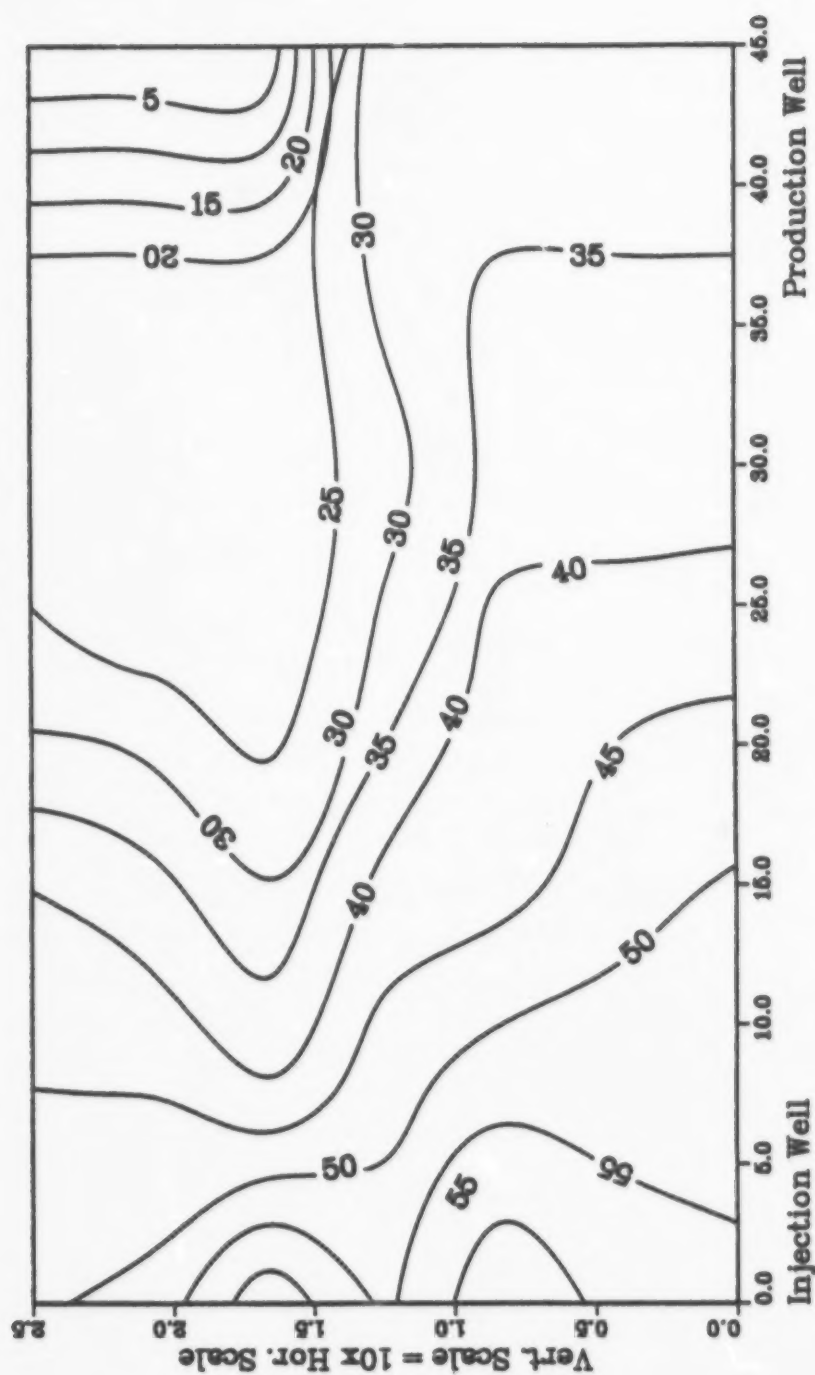


**Figure A.166 :Run 53 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

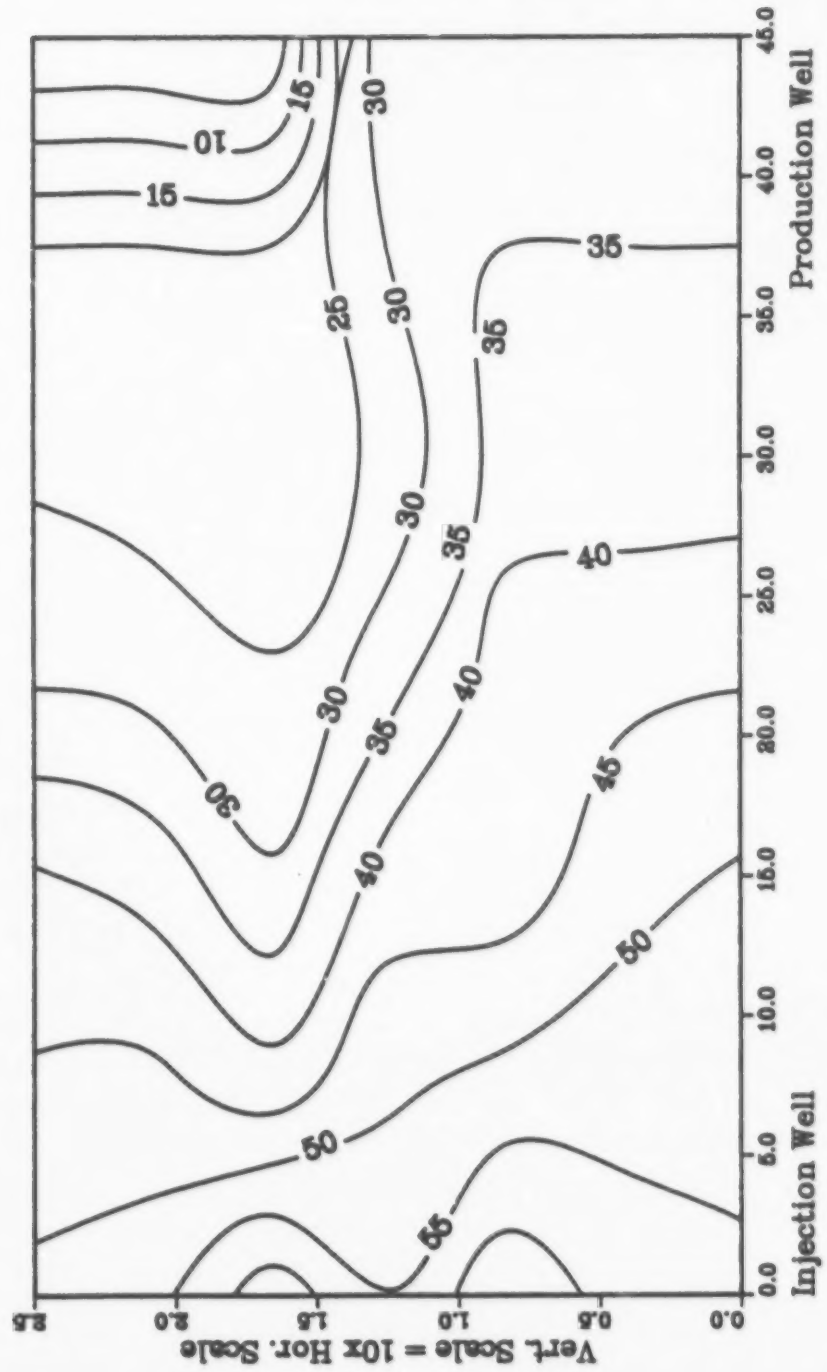
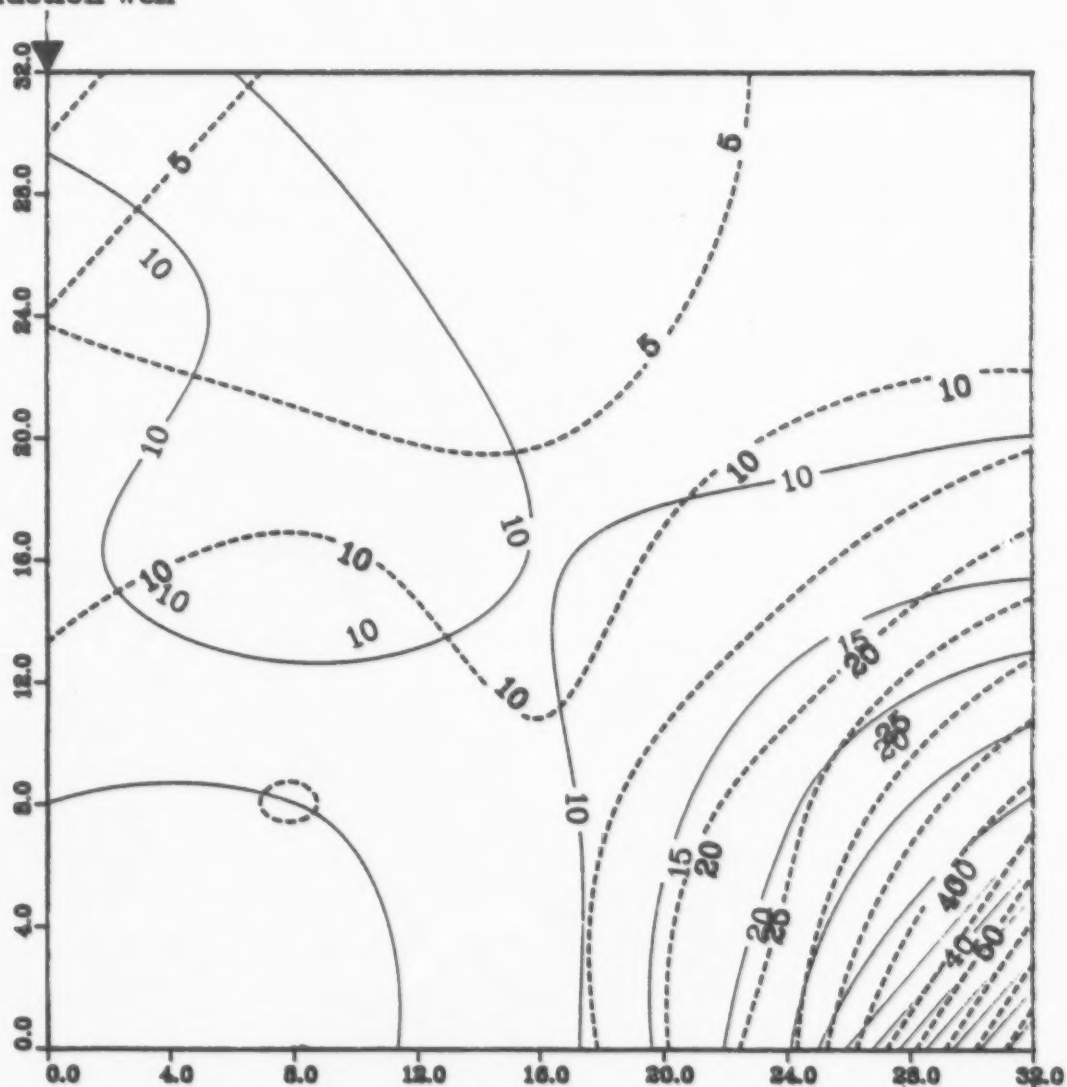


Figure A.167 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A168 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

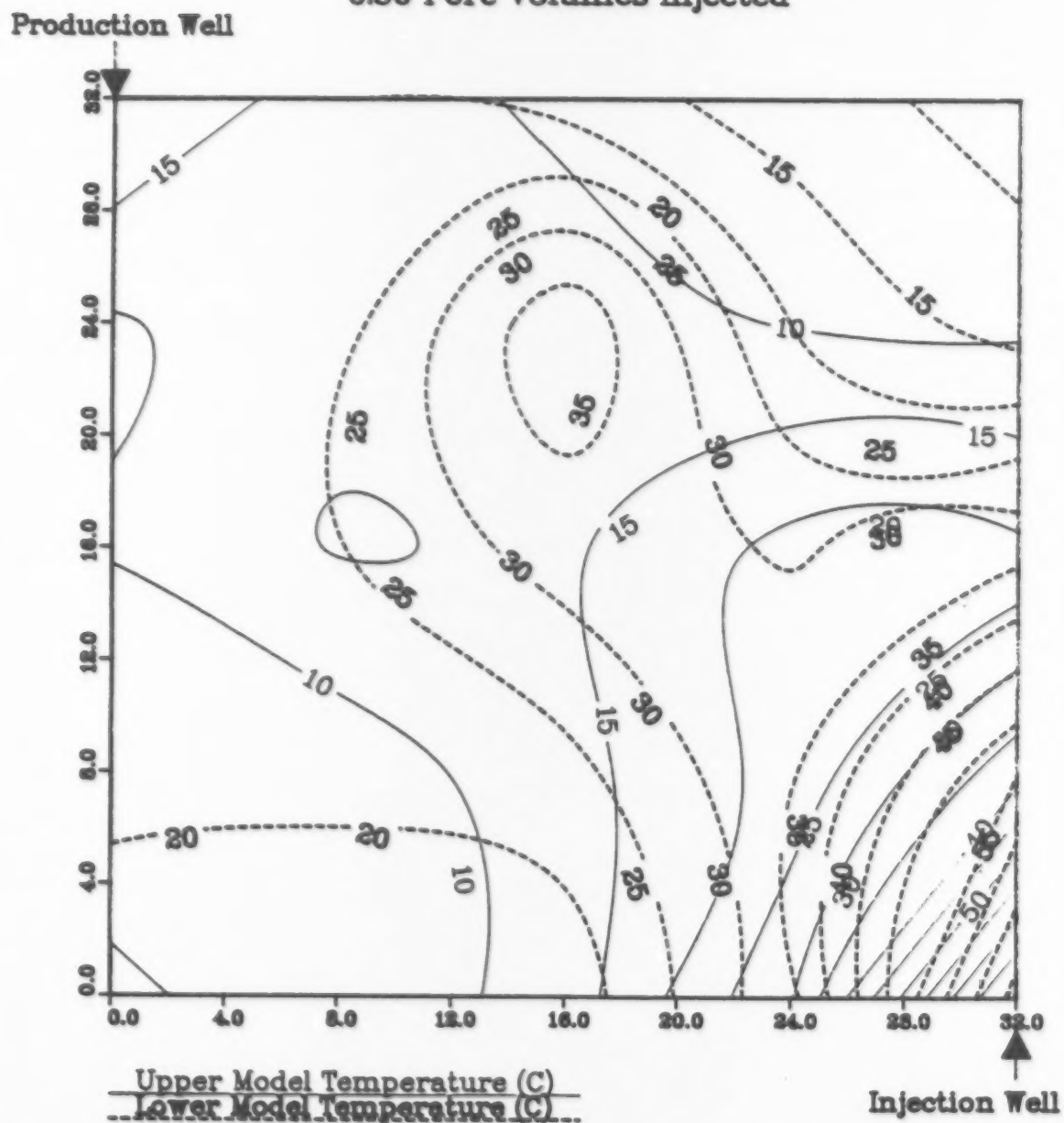
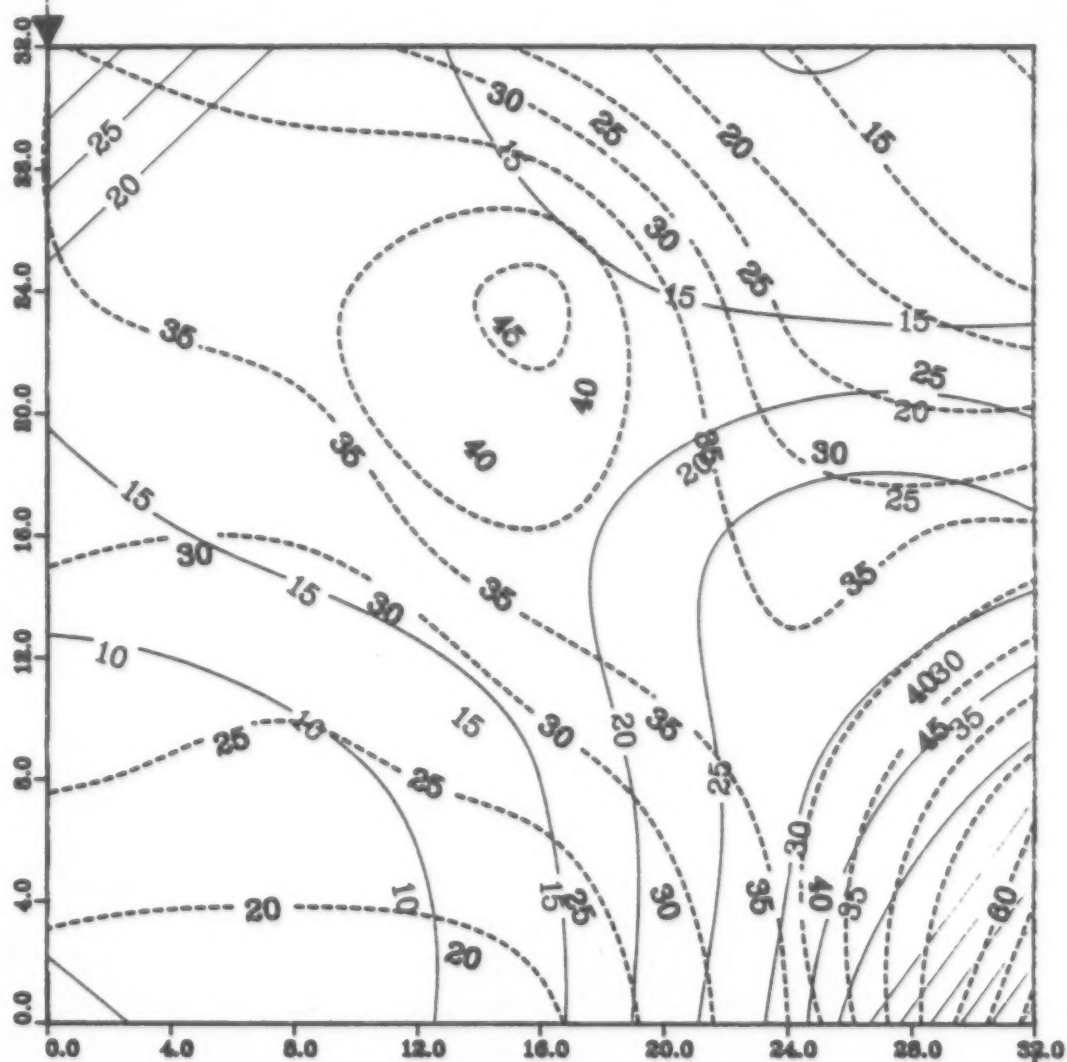


Figure A.169 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.170 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

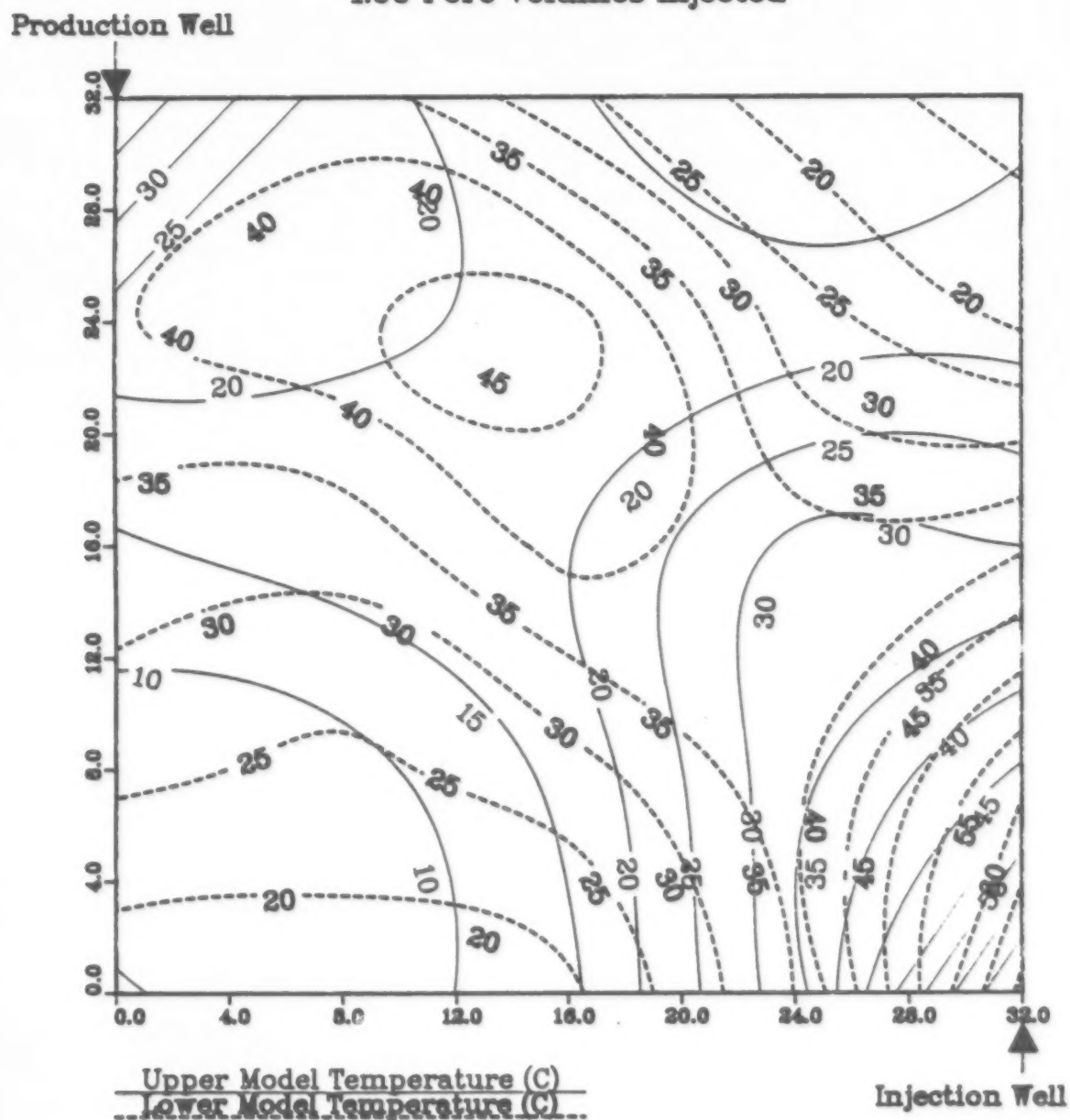
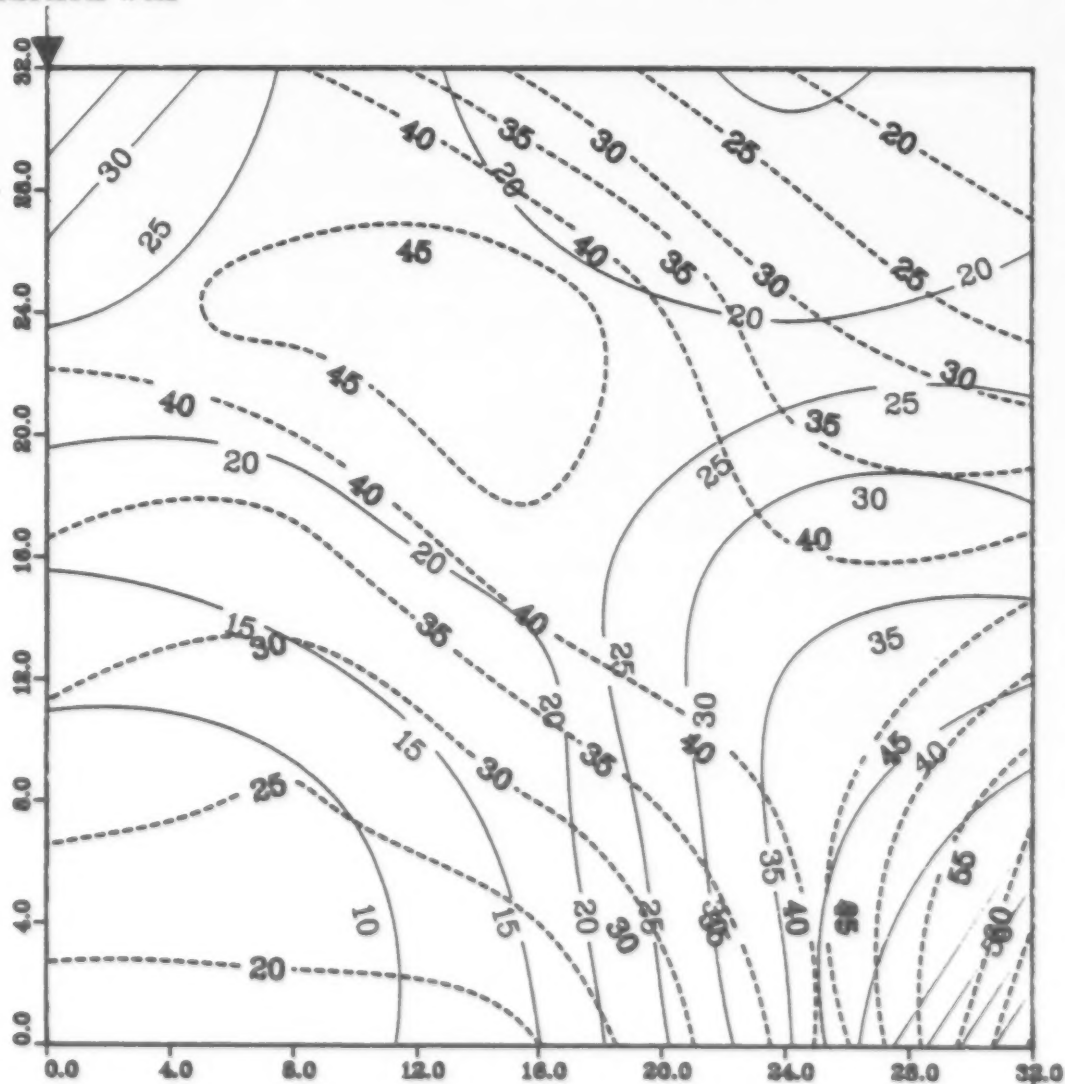


Figure A.171 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

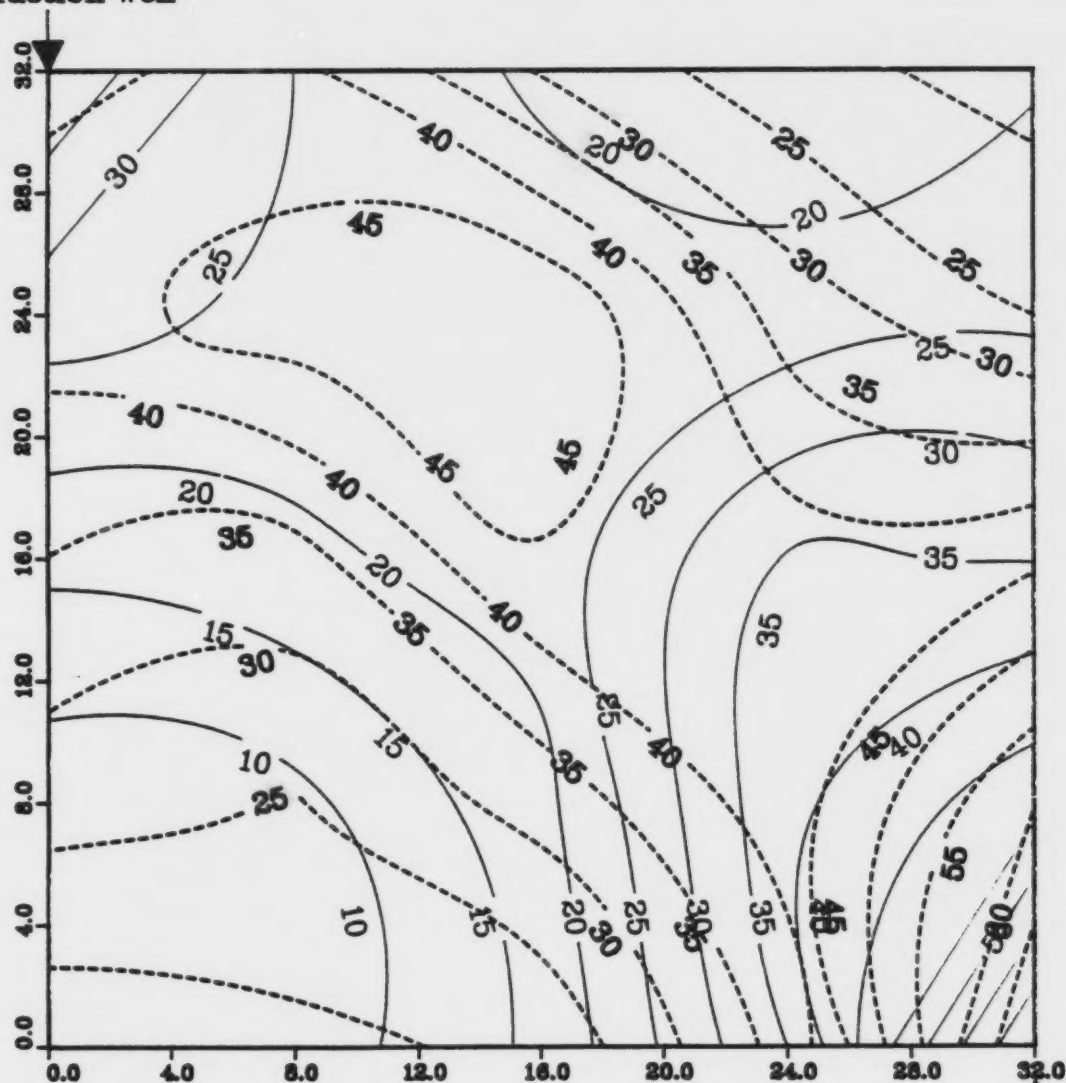
Lower Model Temperature (C)

Injection Well

Figure A.172 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

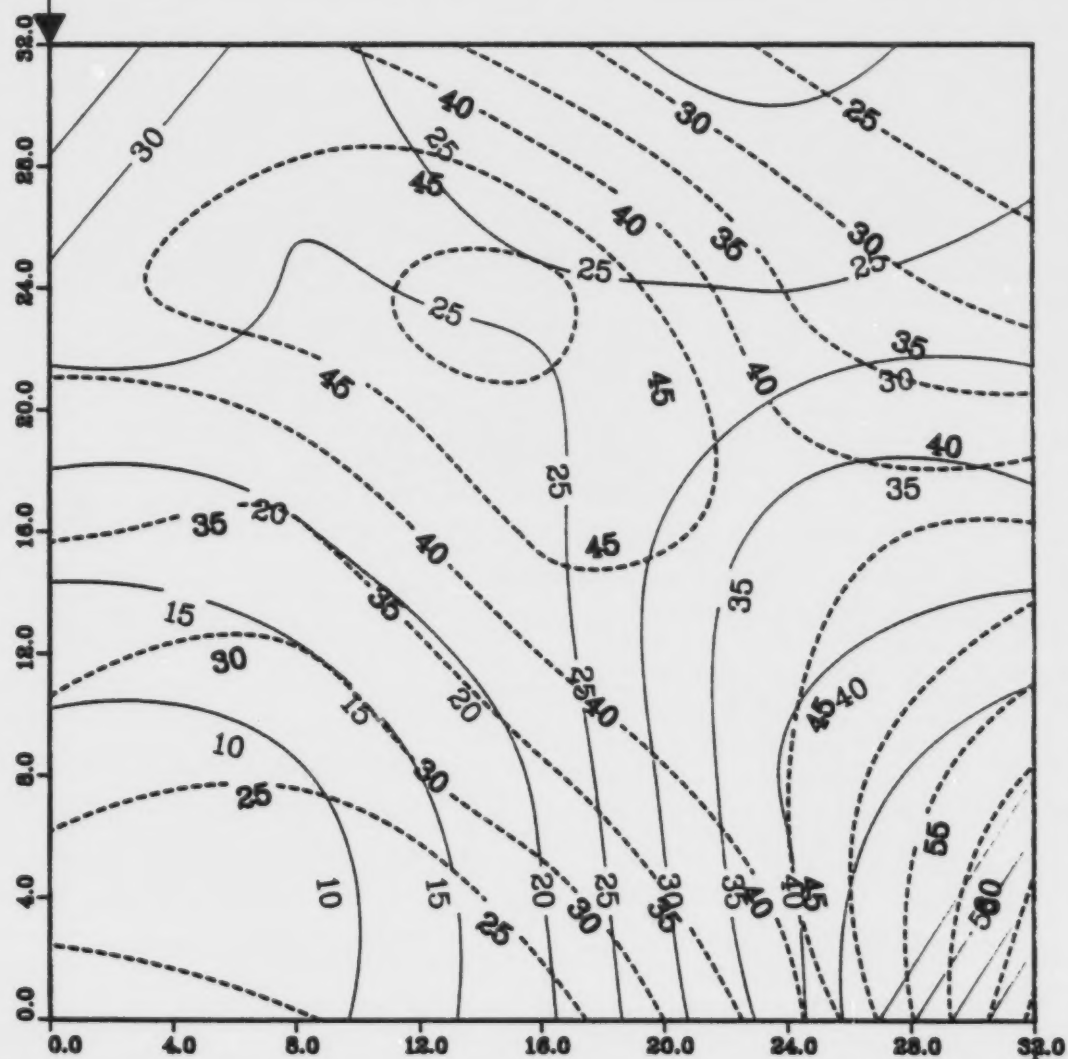
Lower Model Temperature (C)

Injection Well

Figure A.173 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

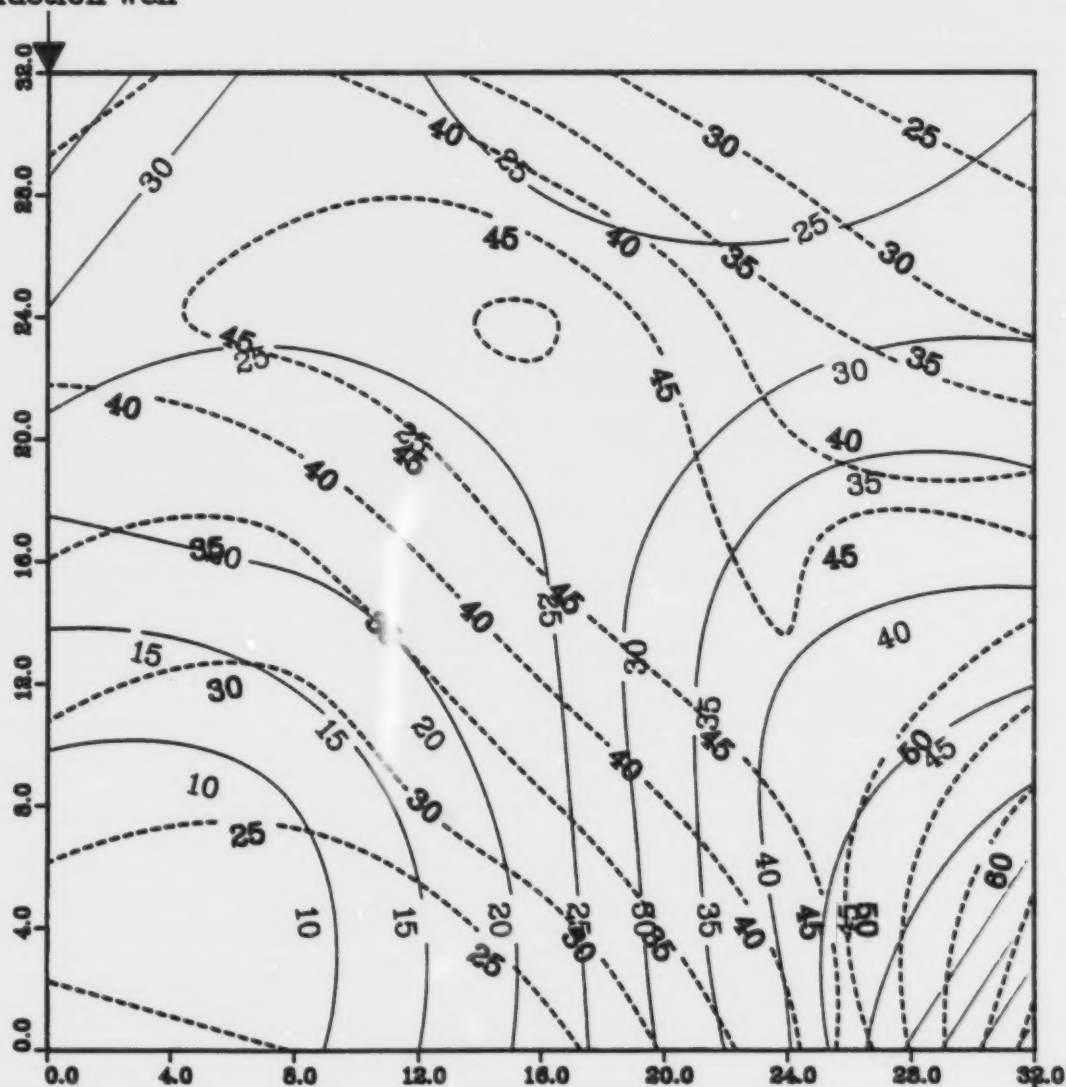
Lower Model Temperature (C)

Injection Well

Figure A174 : Run 54
Solvent-Steamflood in B.W. Model

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

**Figure A.175 :Run 54 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

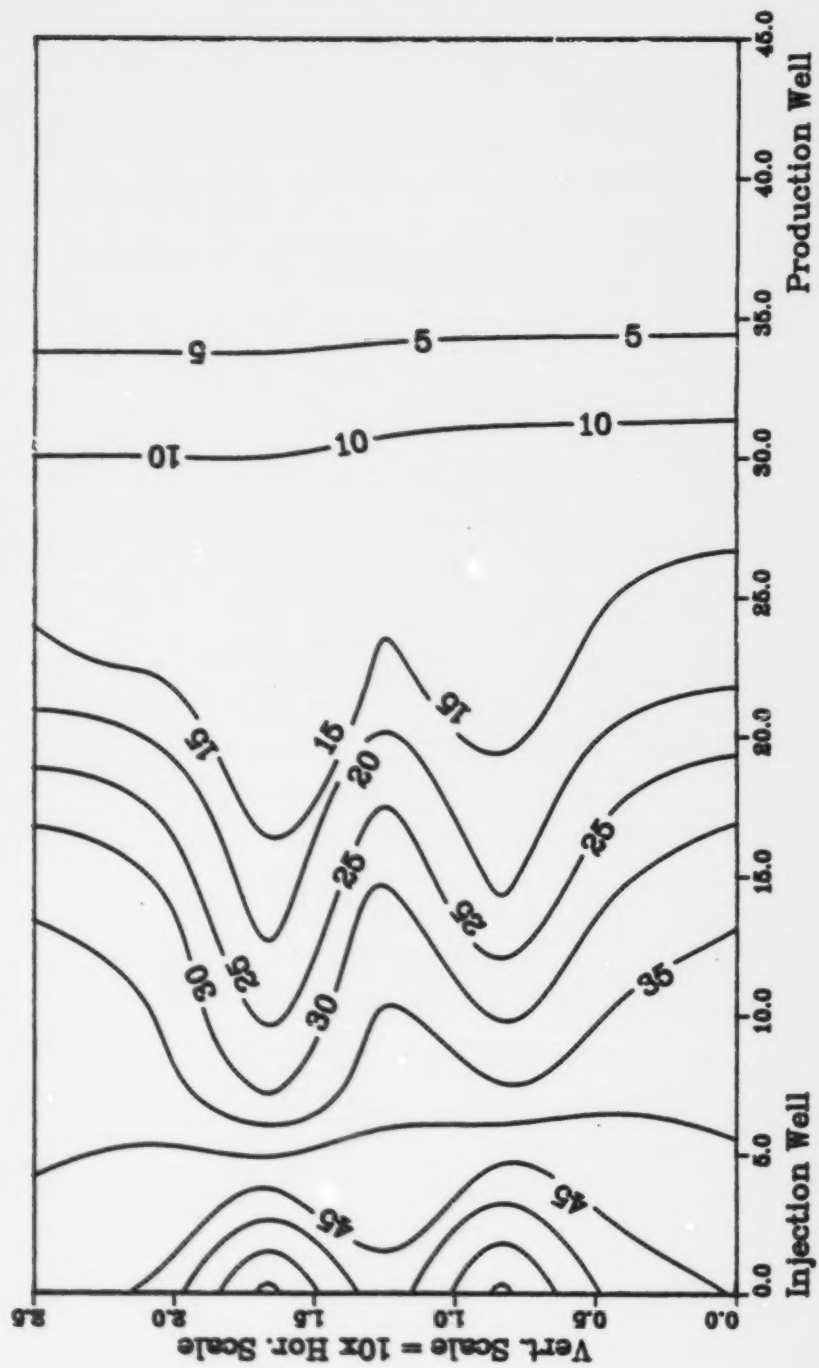


**Figure A.176 :Run 54 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

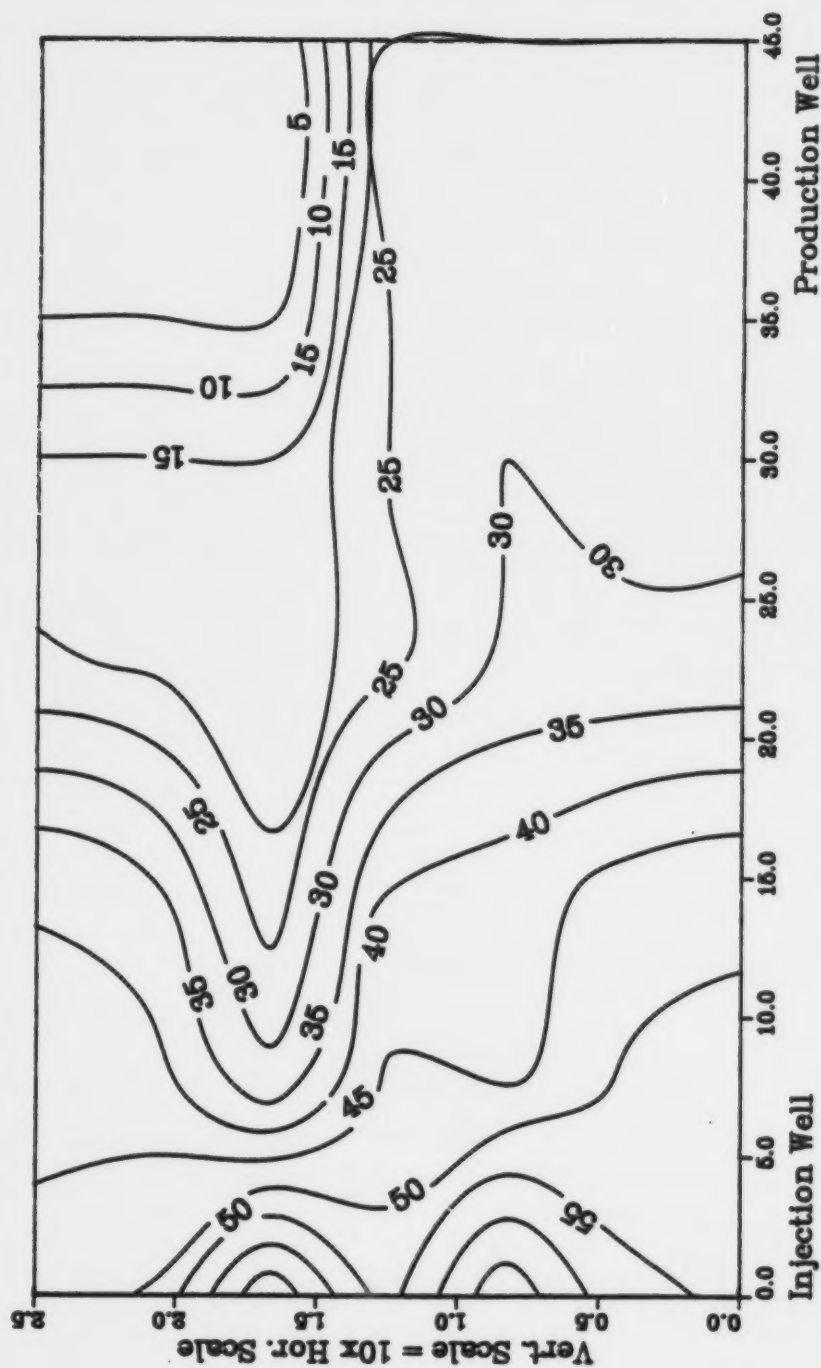


**Figure A.177 :Run 54 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

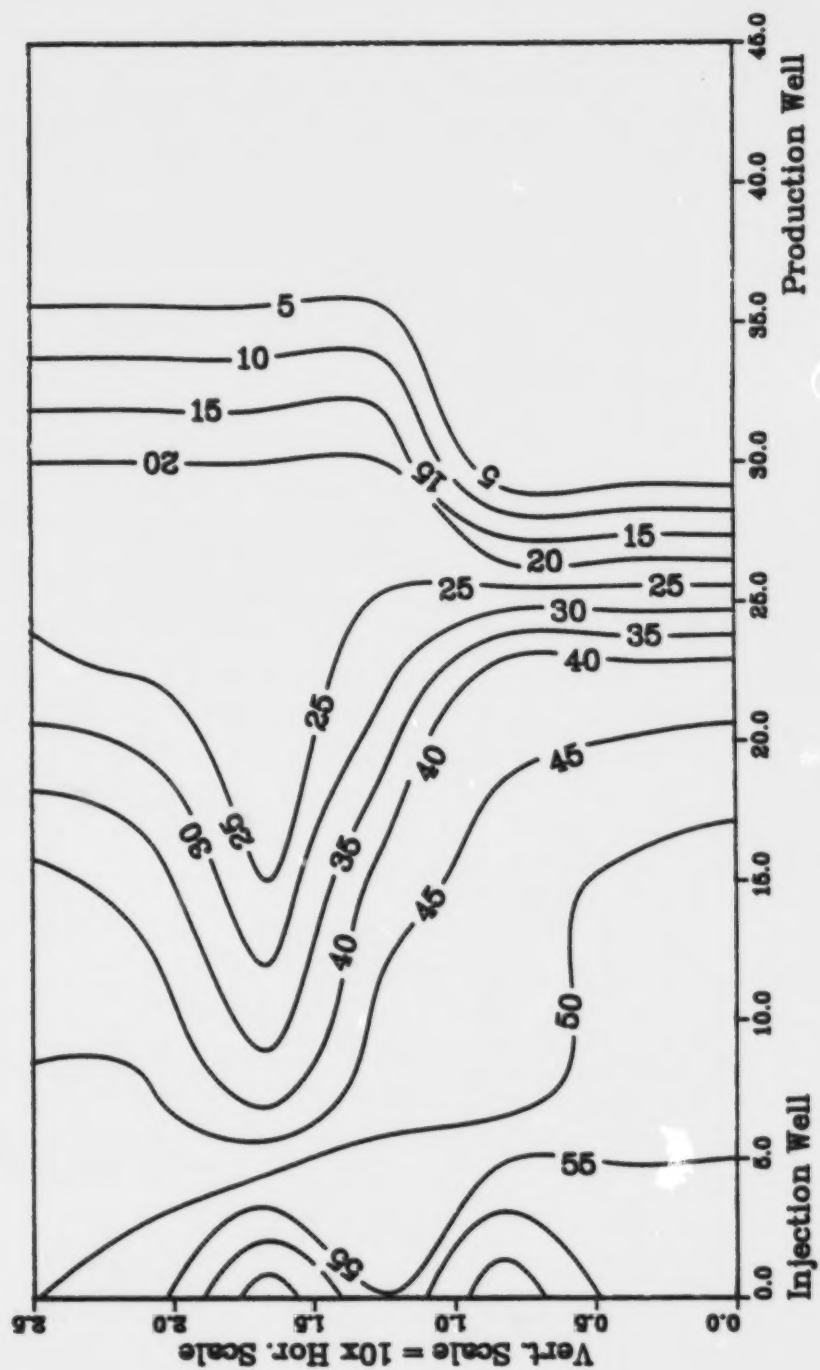


**Figure A.178 :Run 54 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

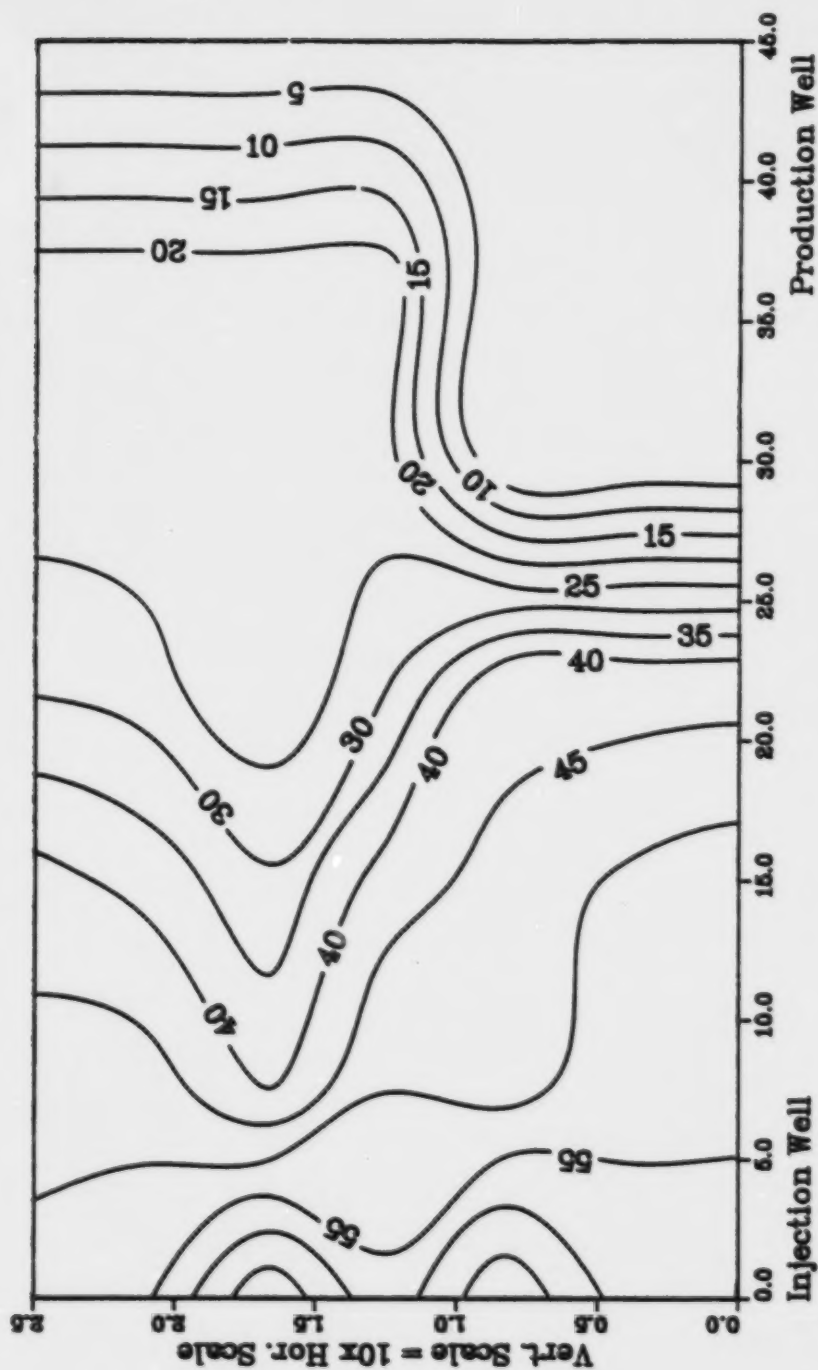


Figure A.179 : Run 55
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
0.25 Pore Volumes Injected

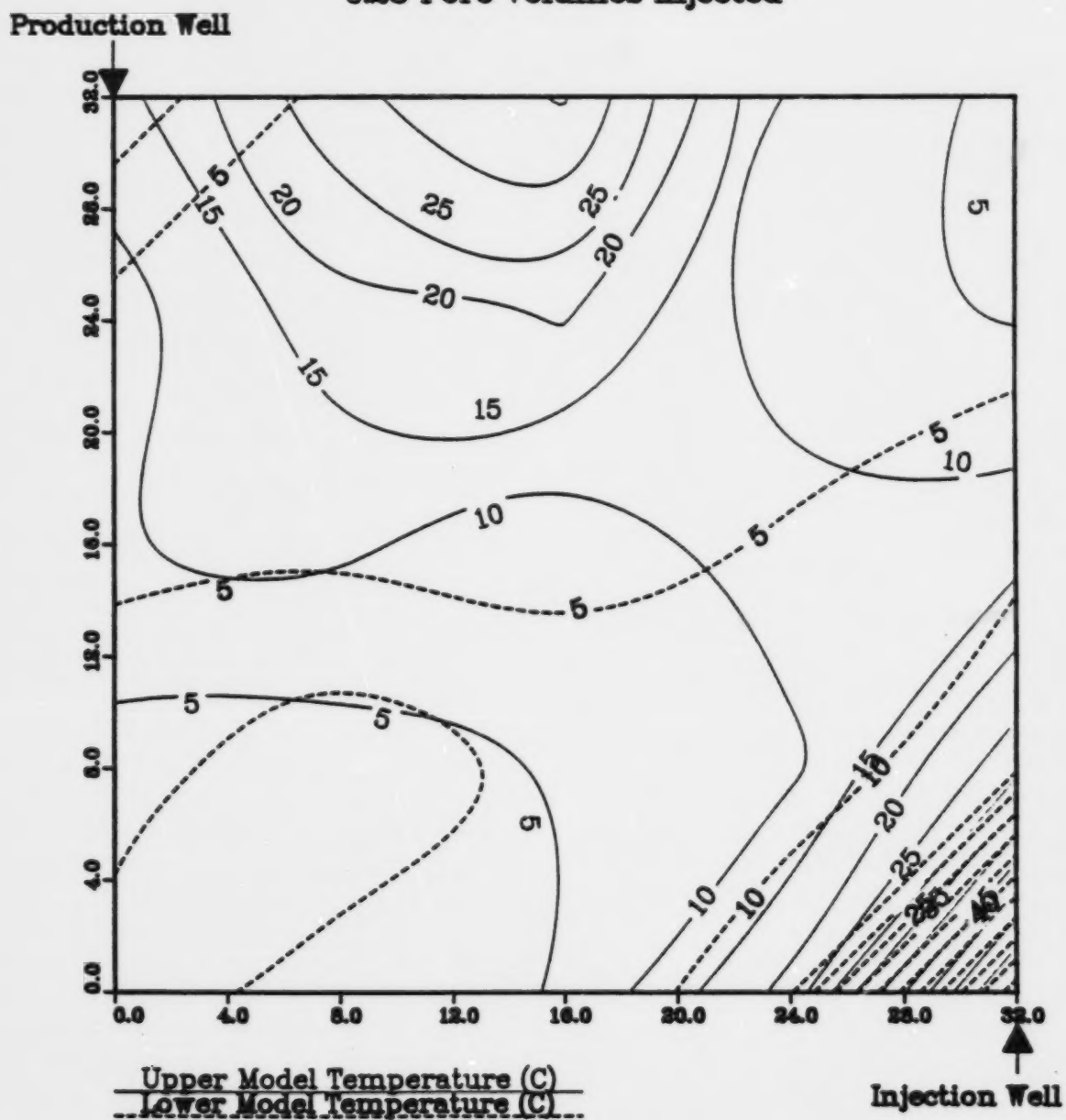
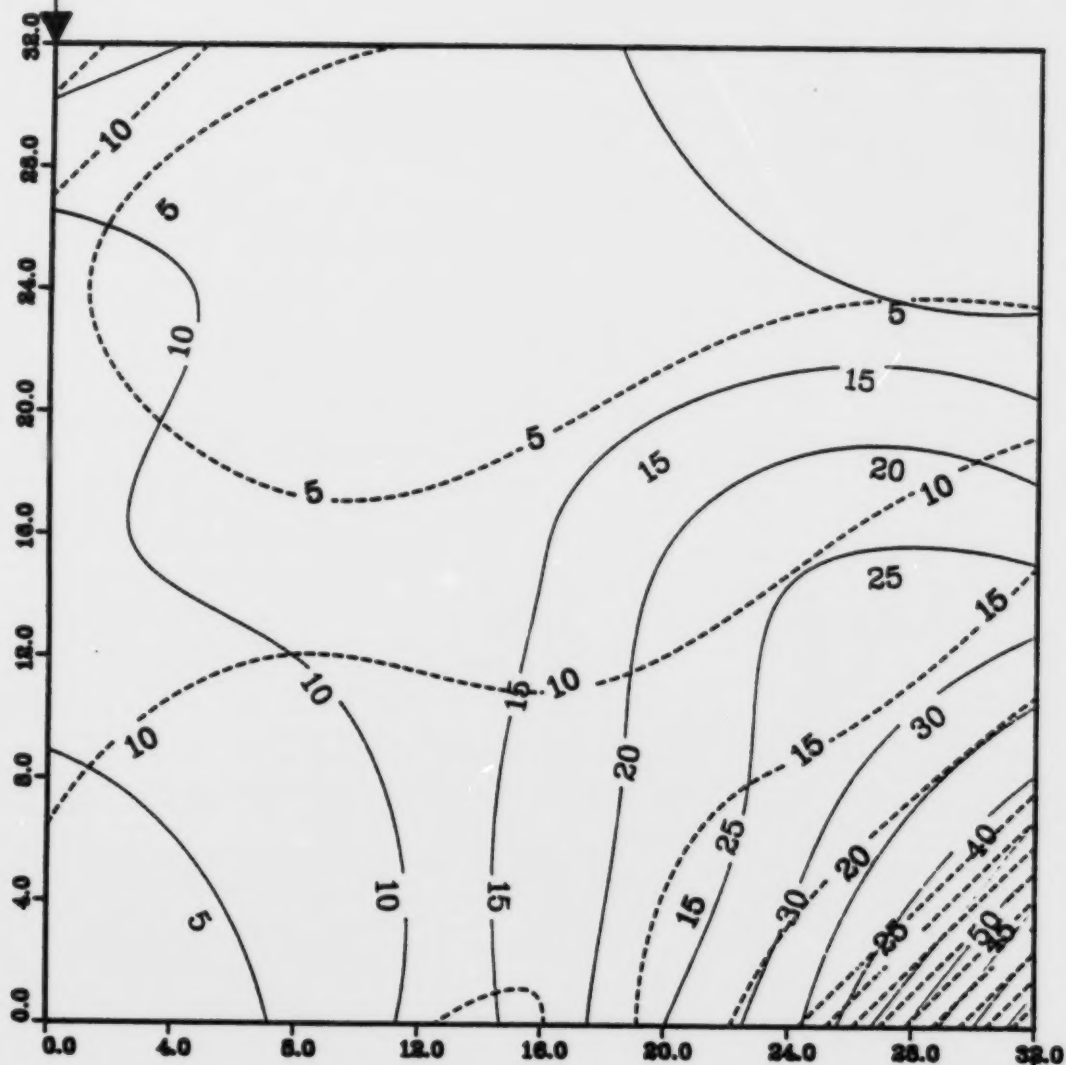


Figure A.180 : Run 55
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.181 : Run 55
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
0.75 Pore Volumes Injected

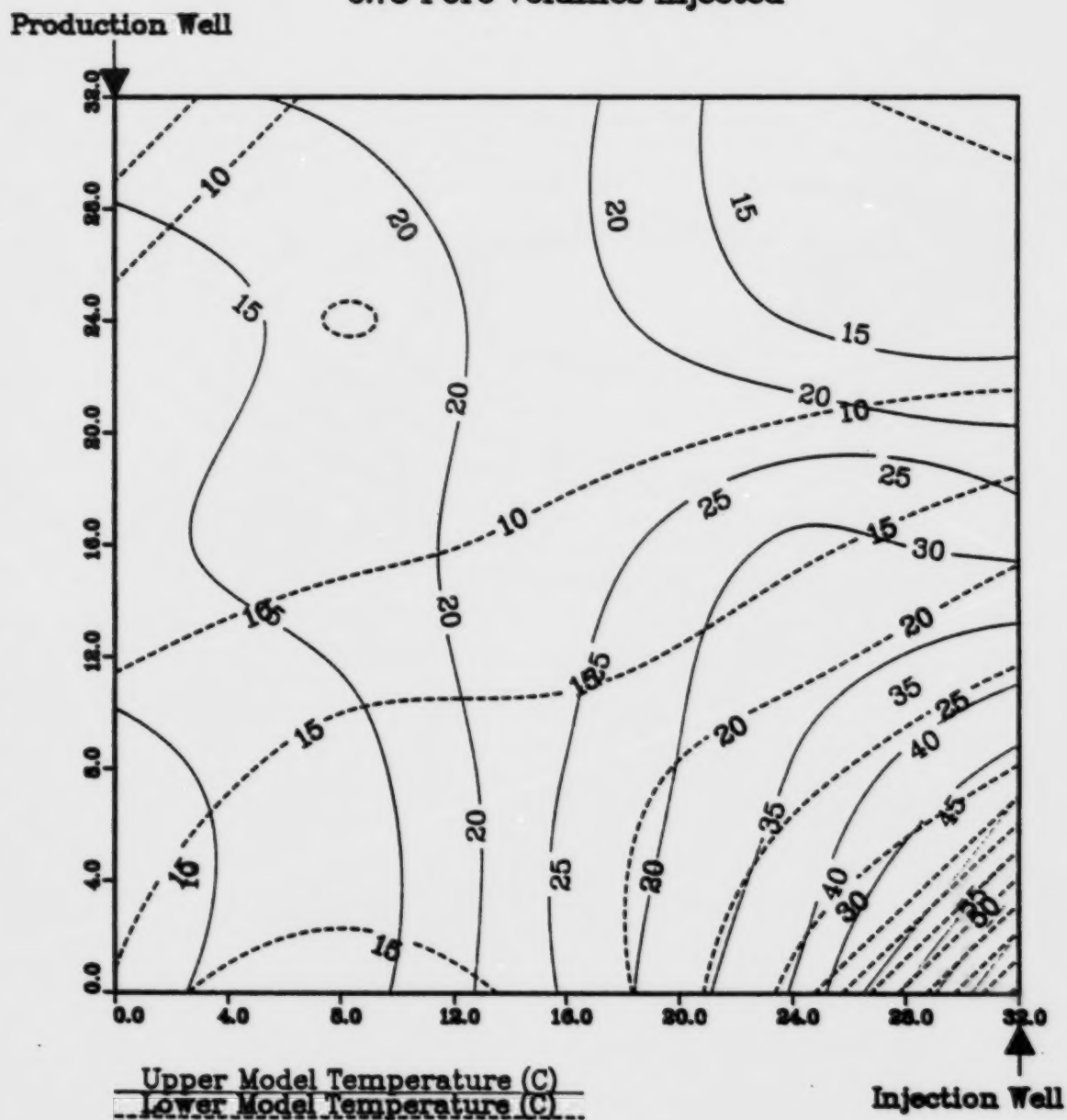
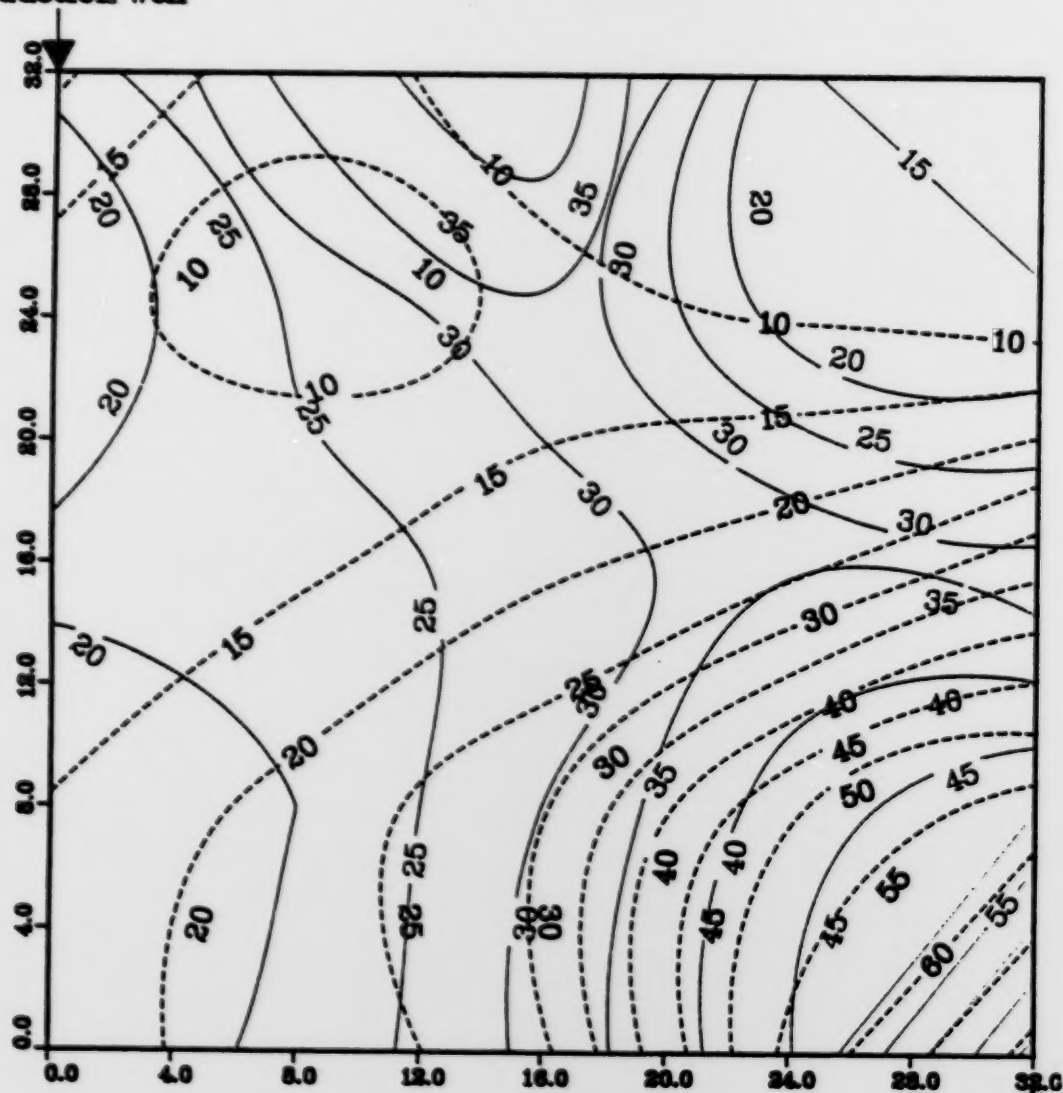


Figure A.182 : Run 55

Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.183 : Run 55
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 1.25 Pore Volumes Injected

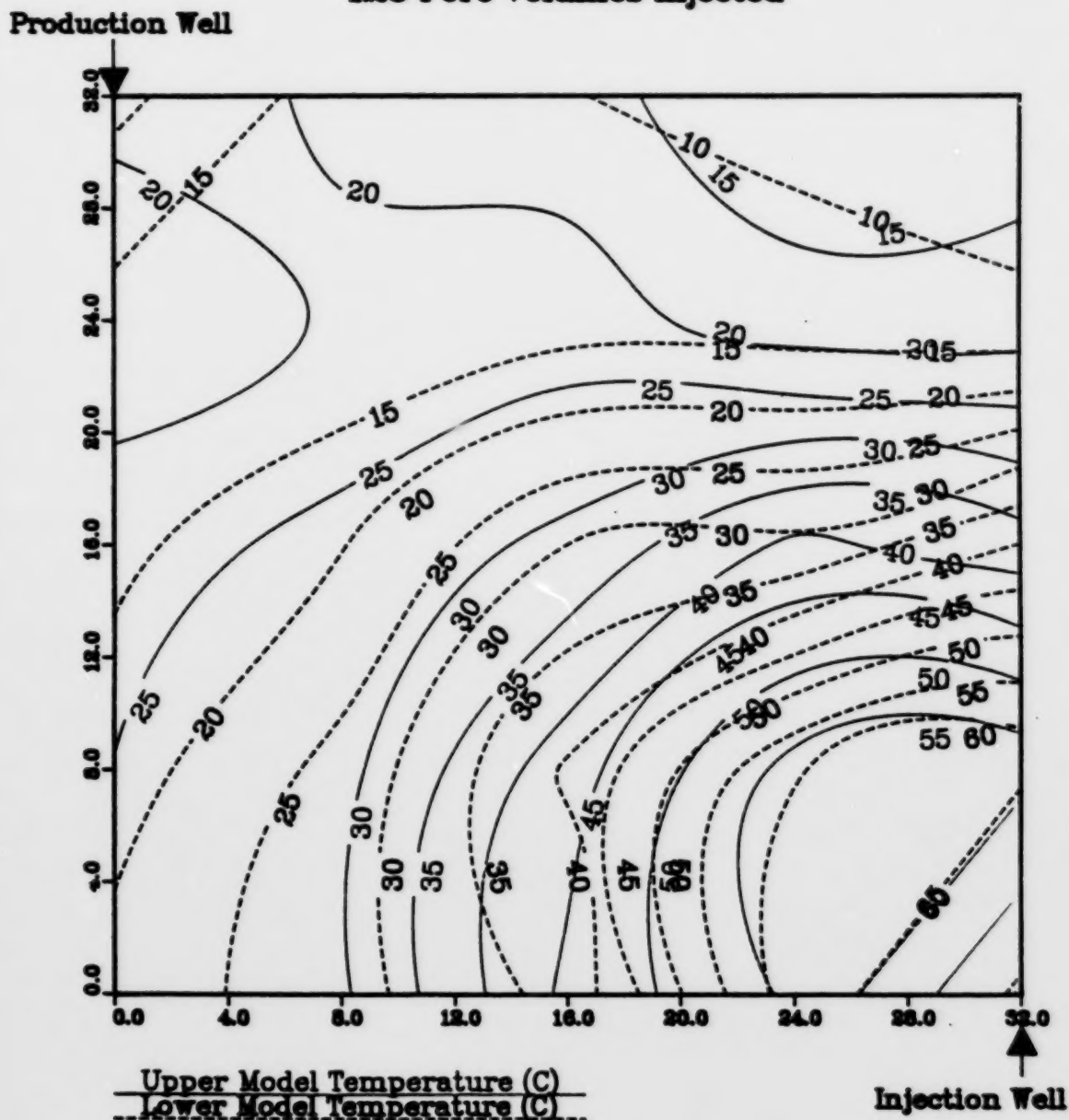


Figure A.184 : Run 55
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
1.50 Pore Volumes Injected

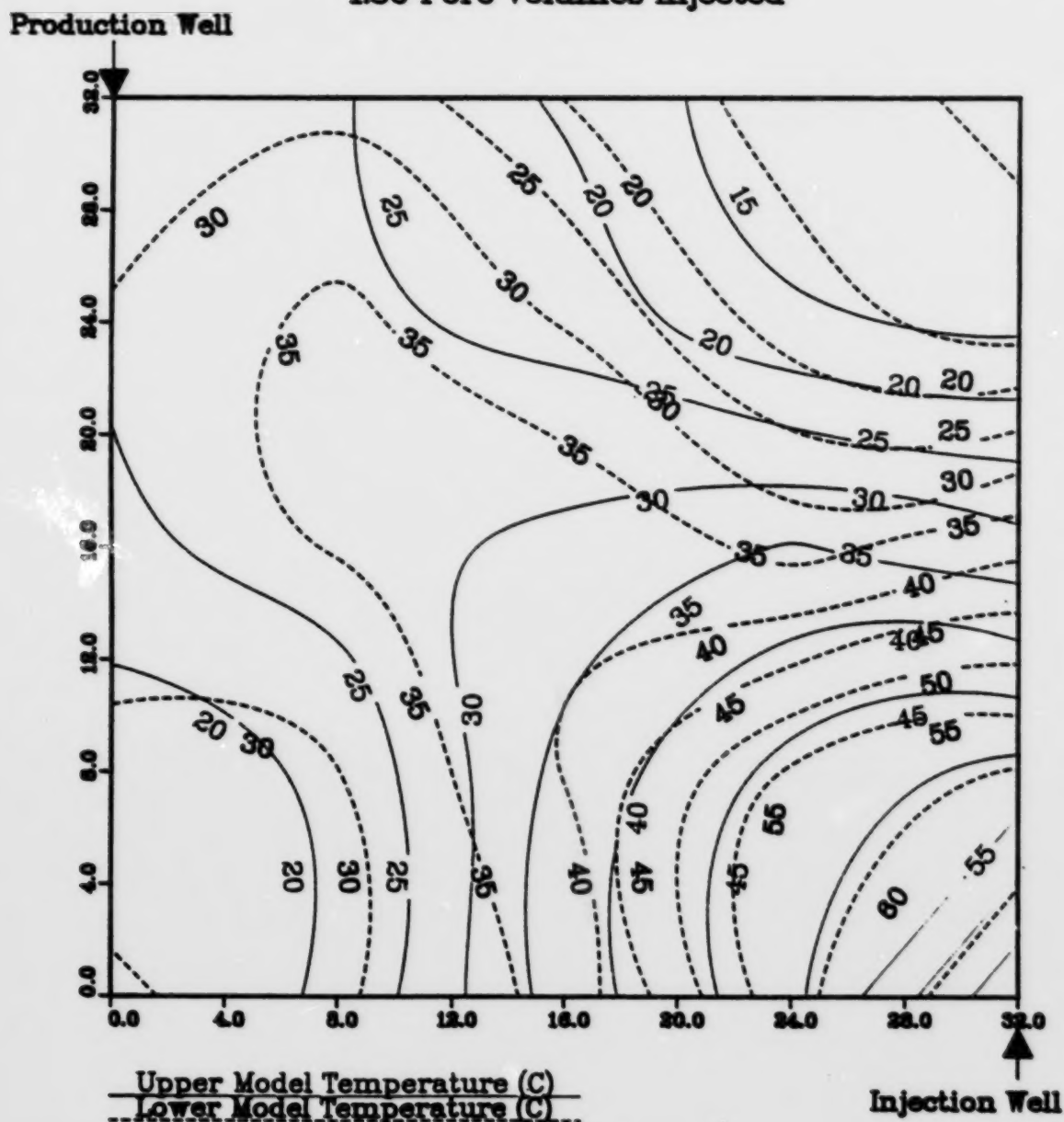
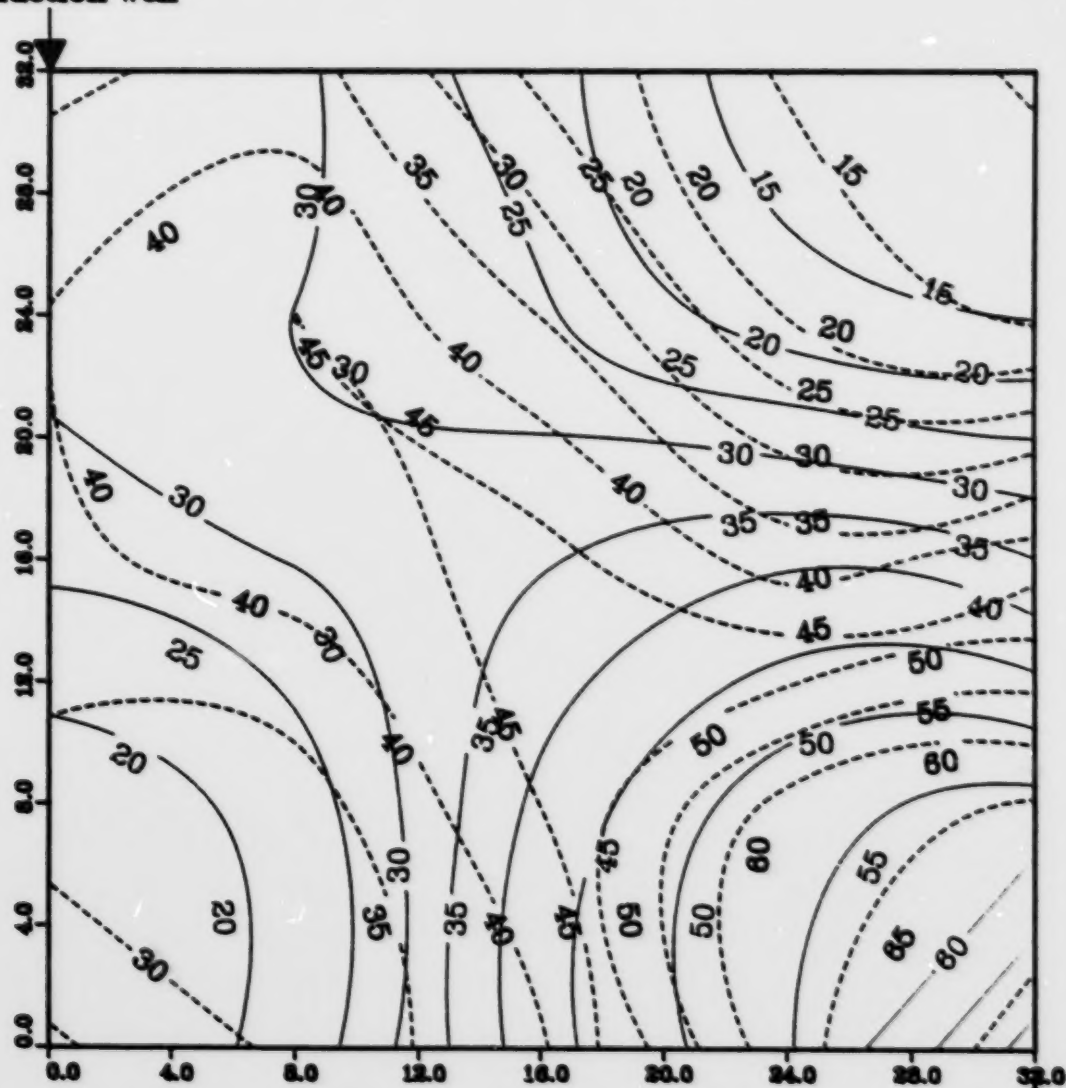


Figure A.185 : Run 55
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

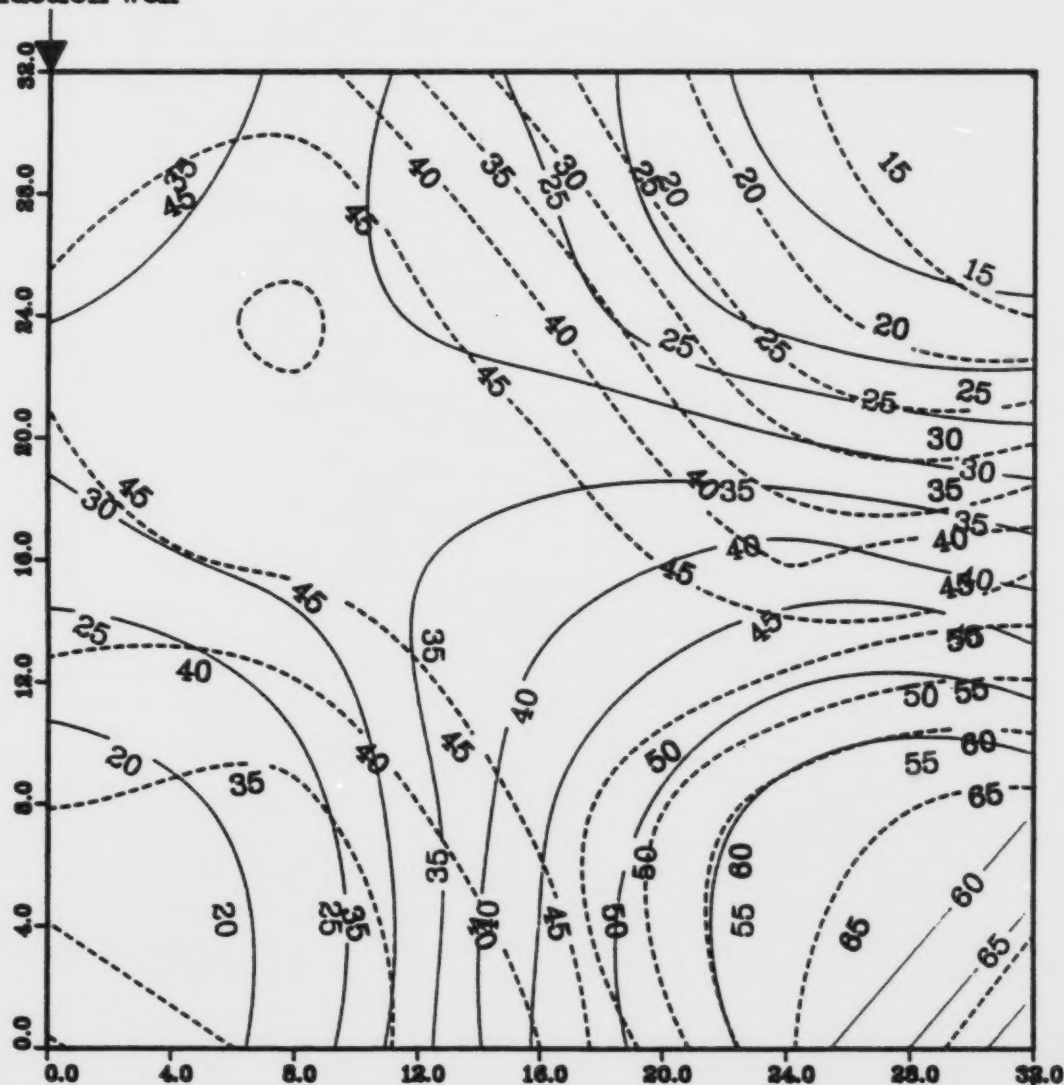
Lower Model Temperature (C)

Injection Well

Figure A.186 : Run 55
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

**Figure A.187 :Run 55 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

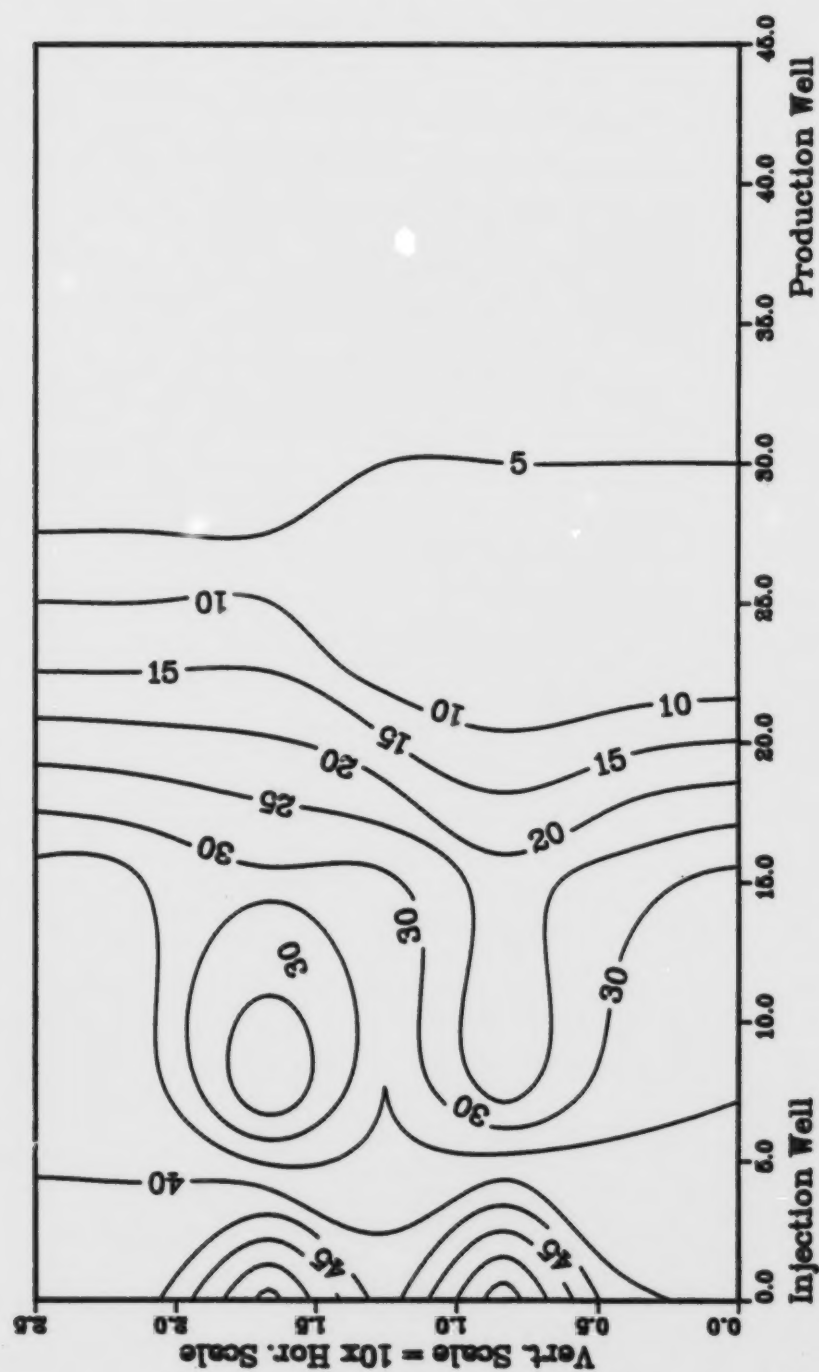


**Figure A.188 :Run 55 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

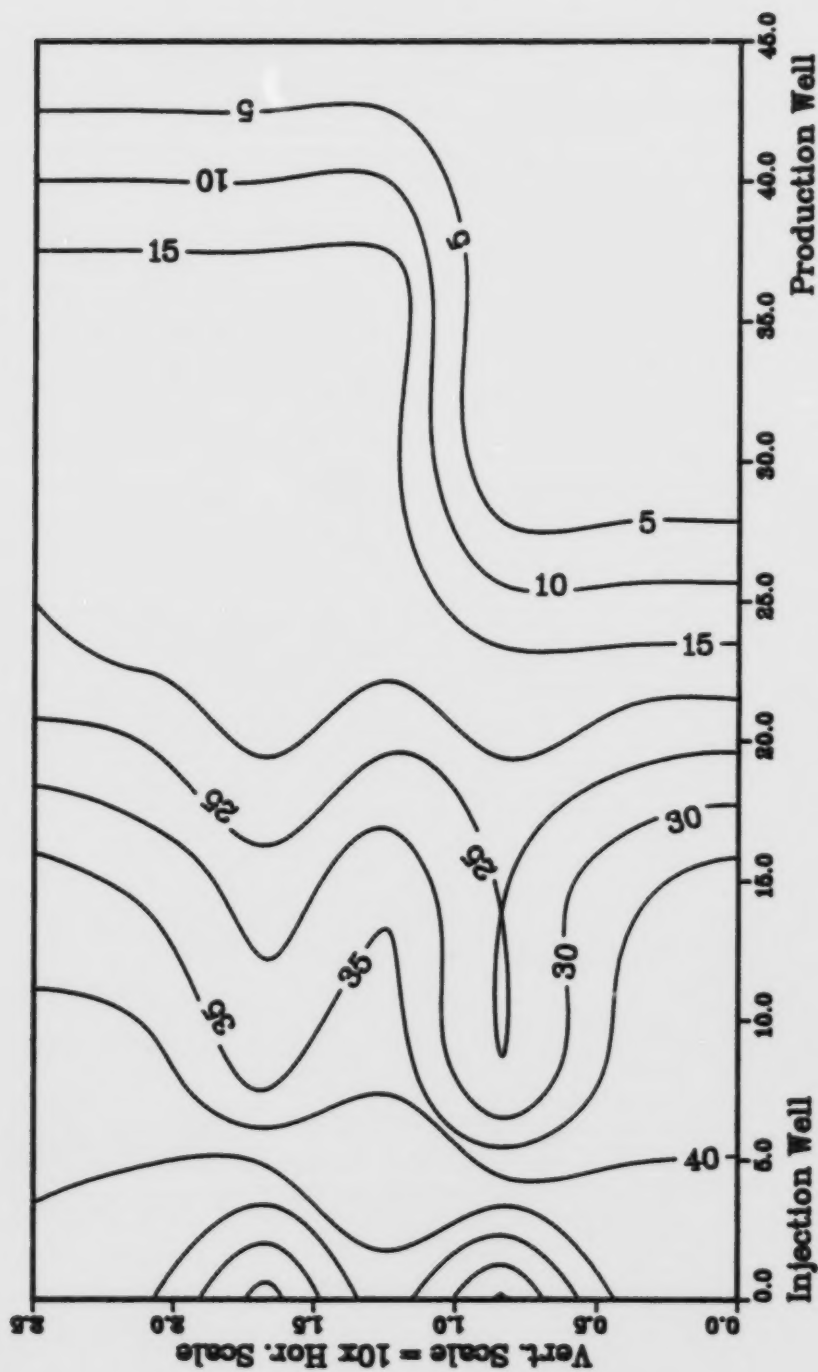


**Figure A.189: Run 55 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

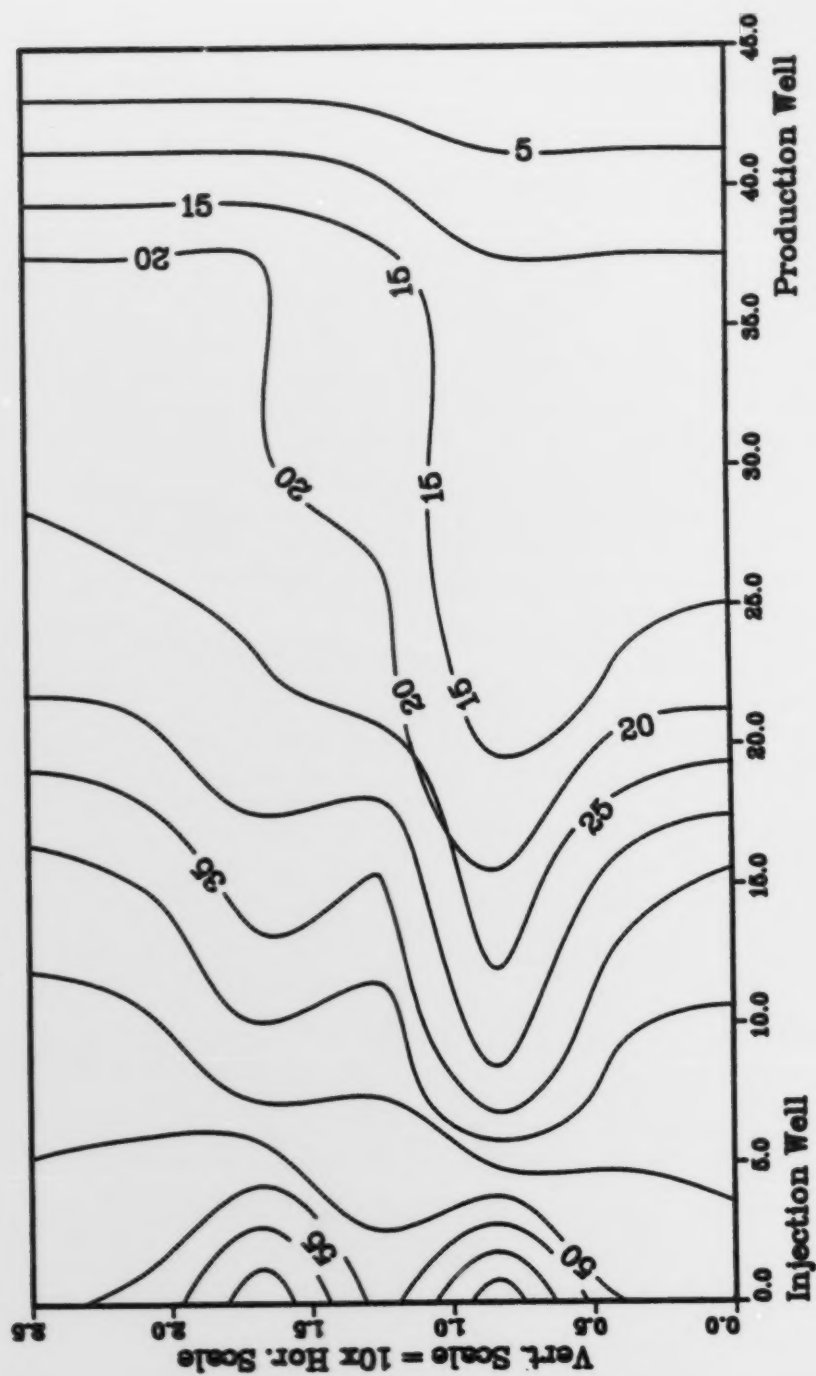


**Figure A.190 :Run 55 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

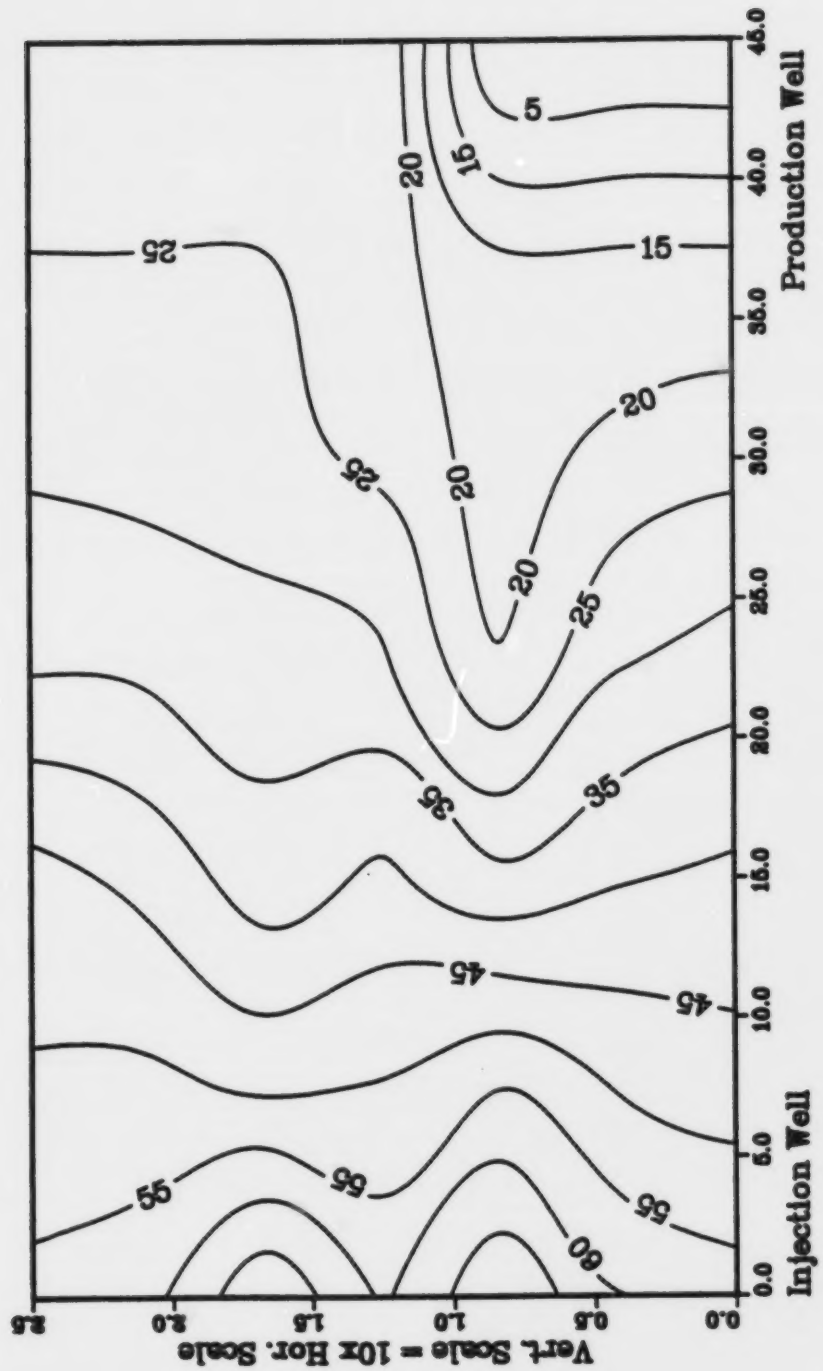
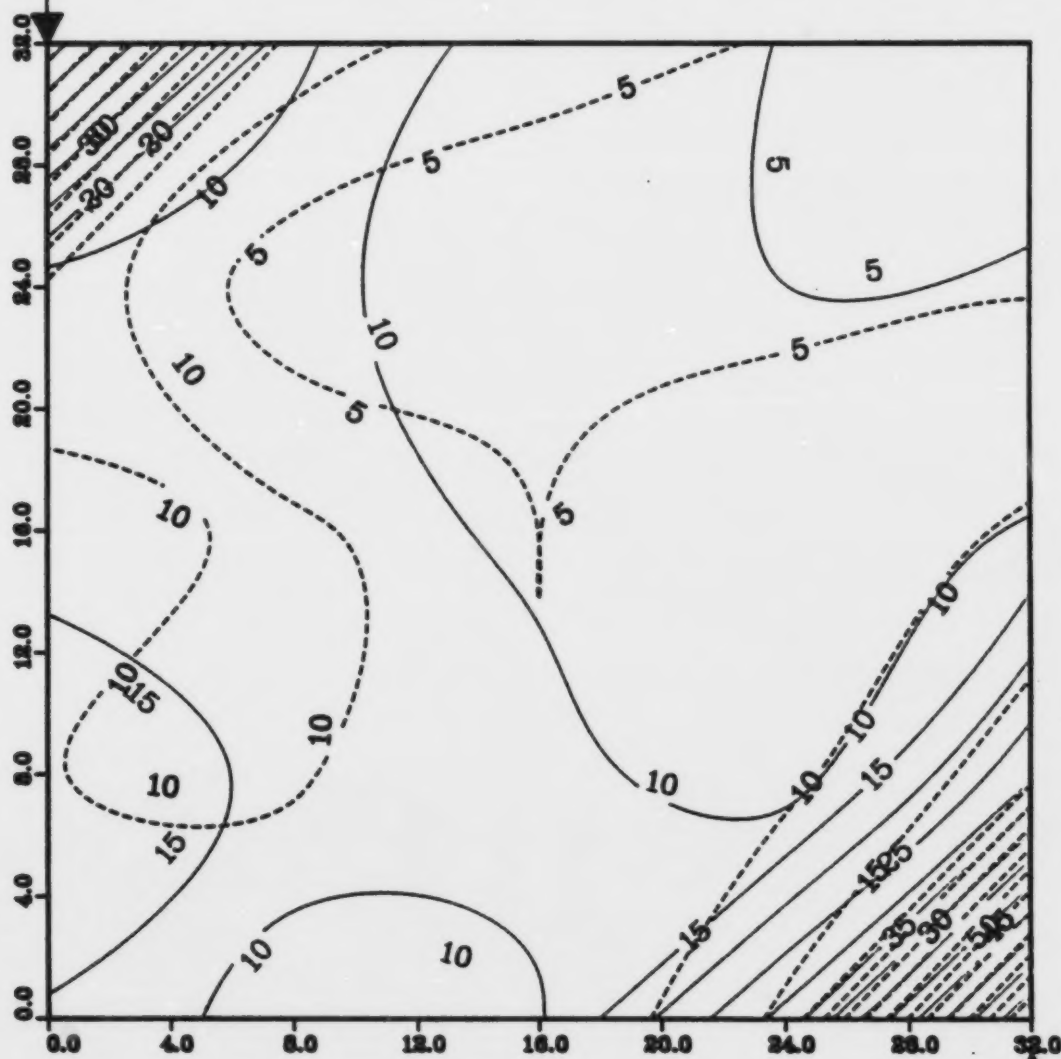


Figure A.191 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

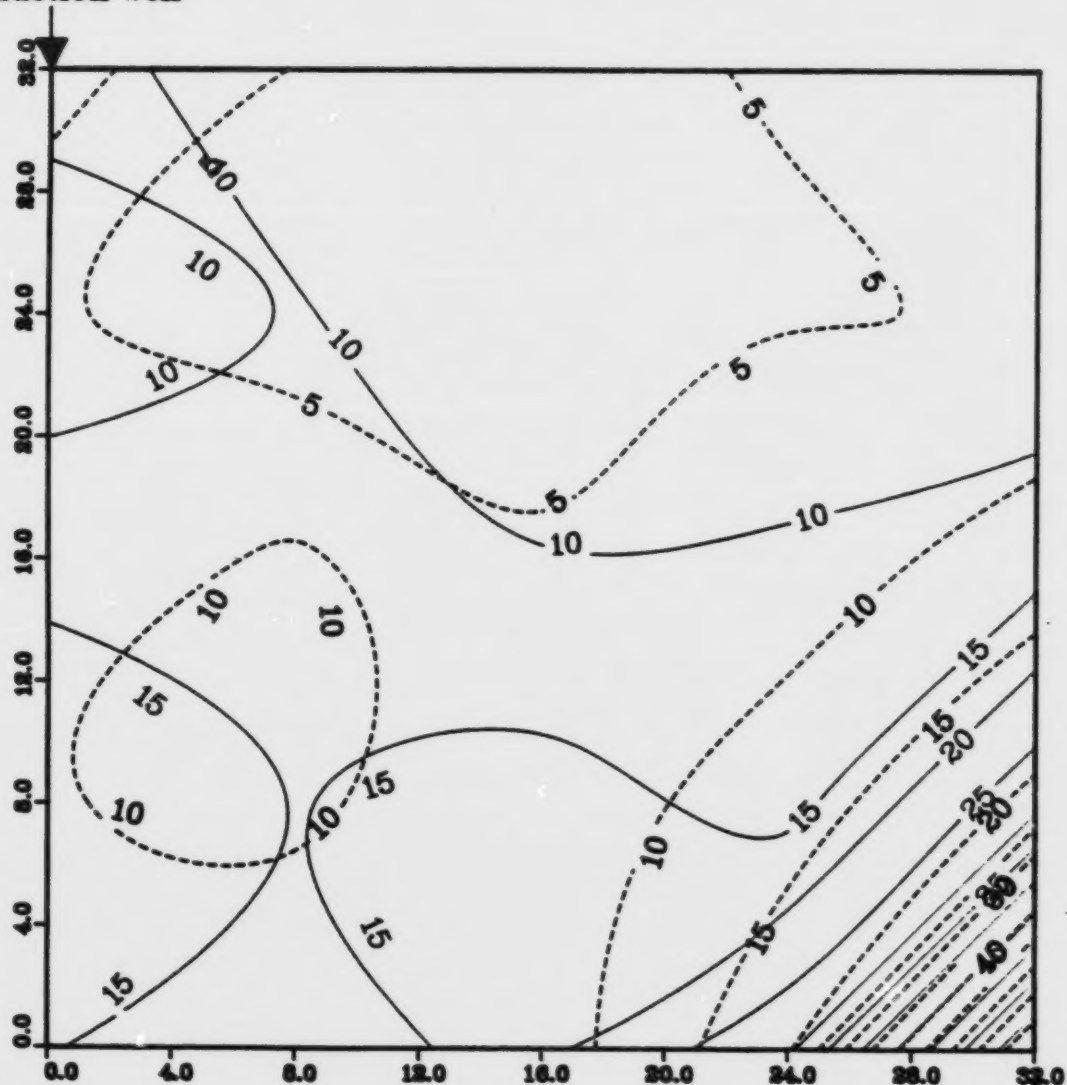
Lower Model Temperature (C)

Injection Well

Figure A.192 : Run 56
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

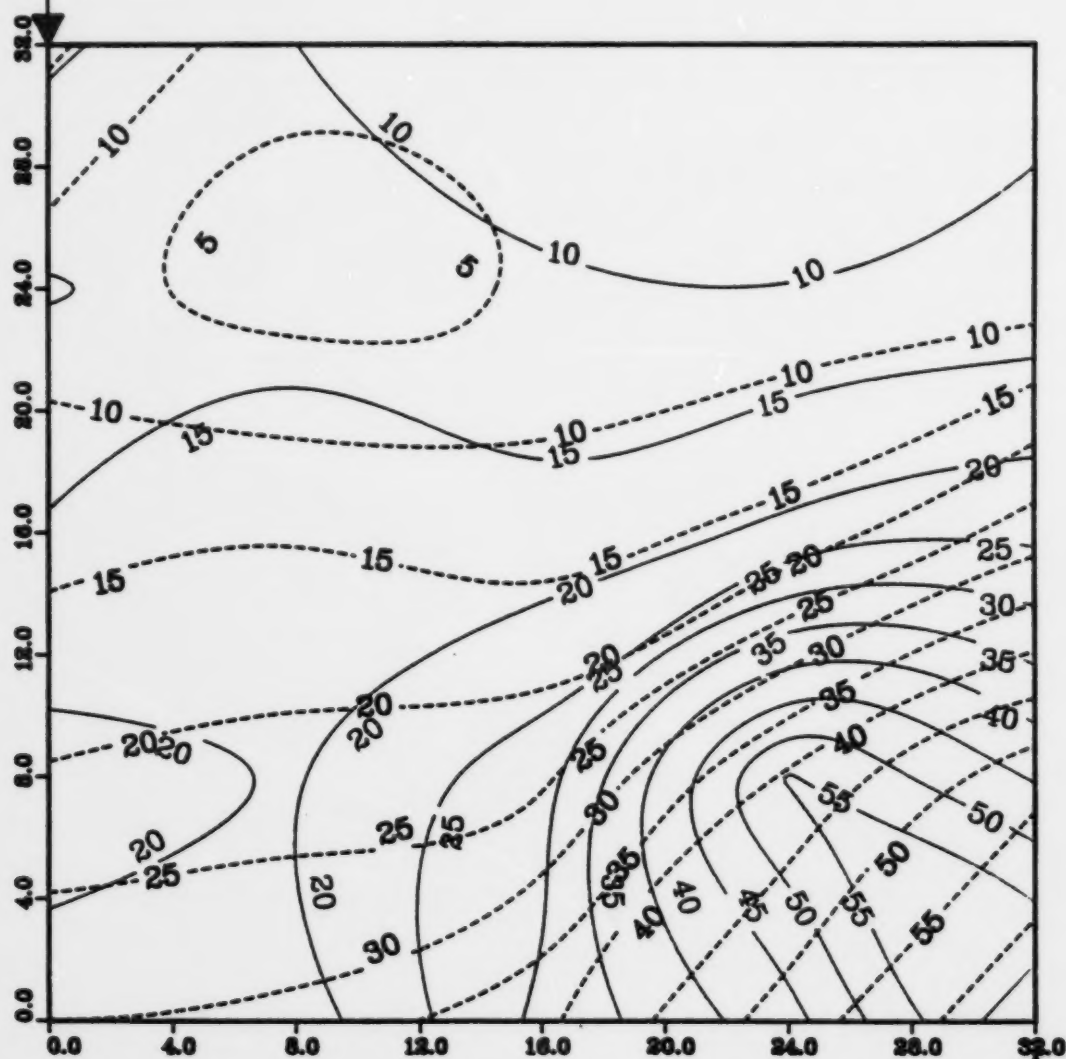
Lower Model Temperature (C)

Injection Well

Figure A.193 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
 Lower Model Temperature (C)

Injection Well

Figure A.194 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 1.00 Pore Volumes Injected

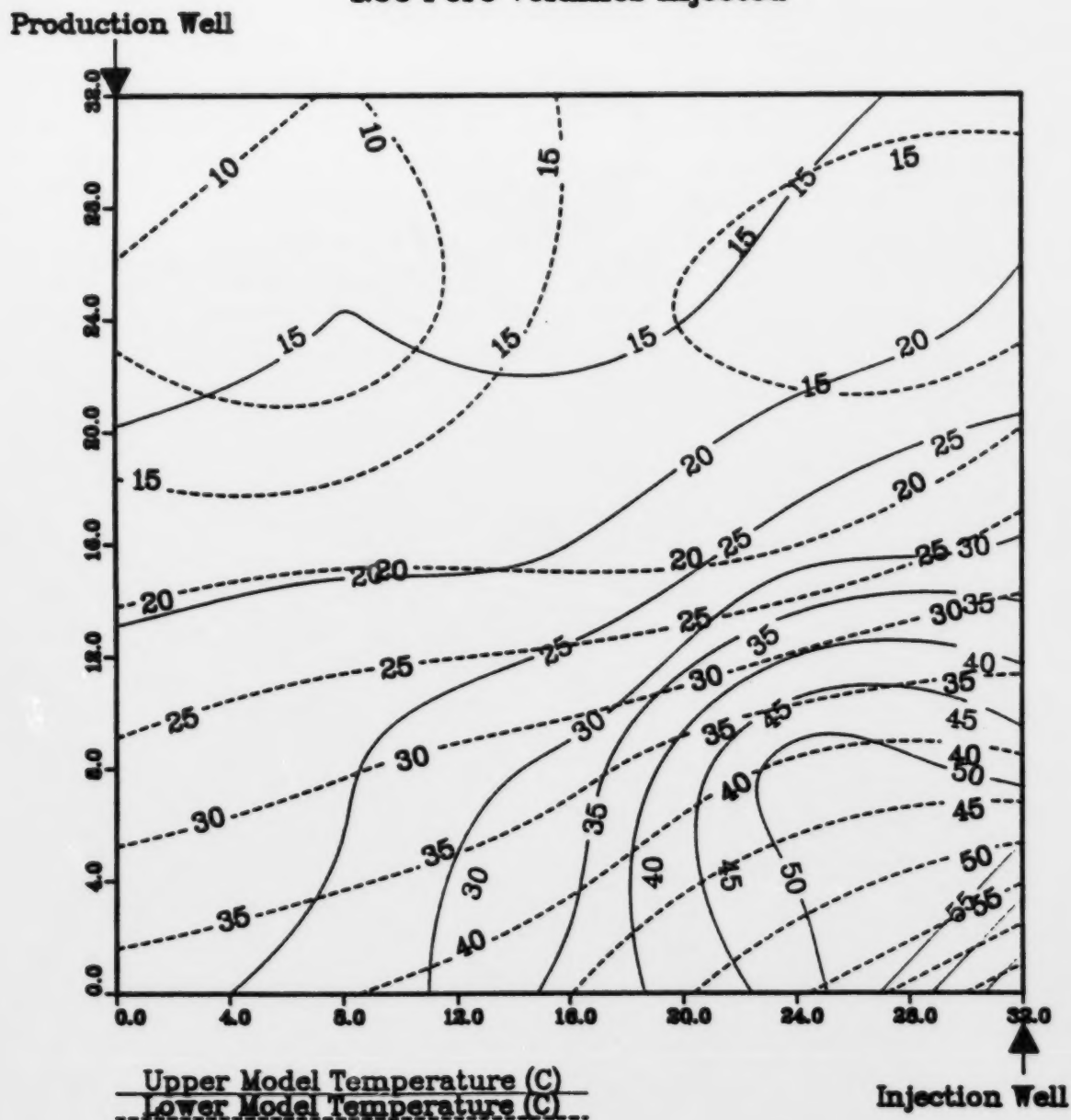
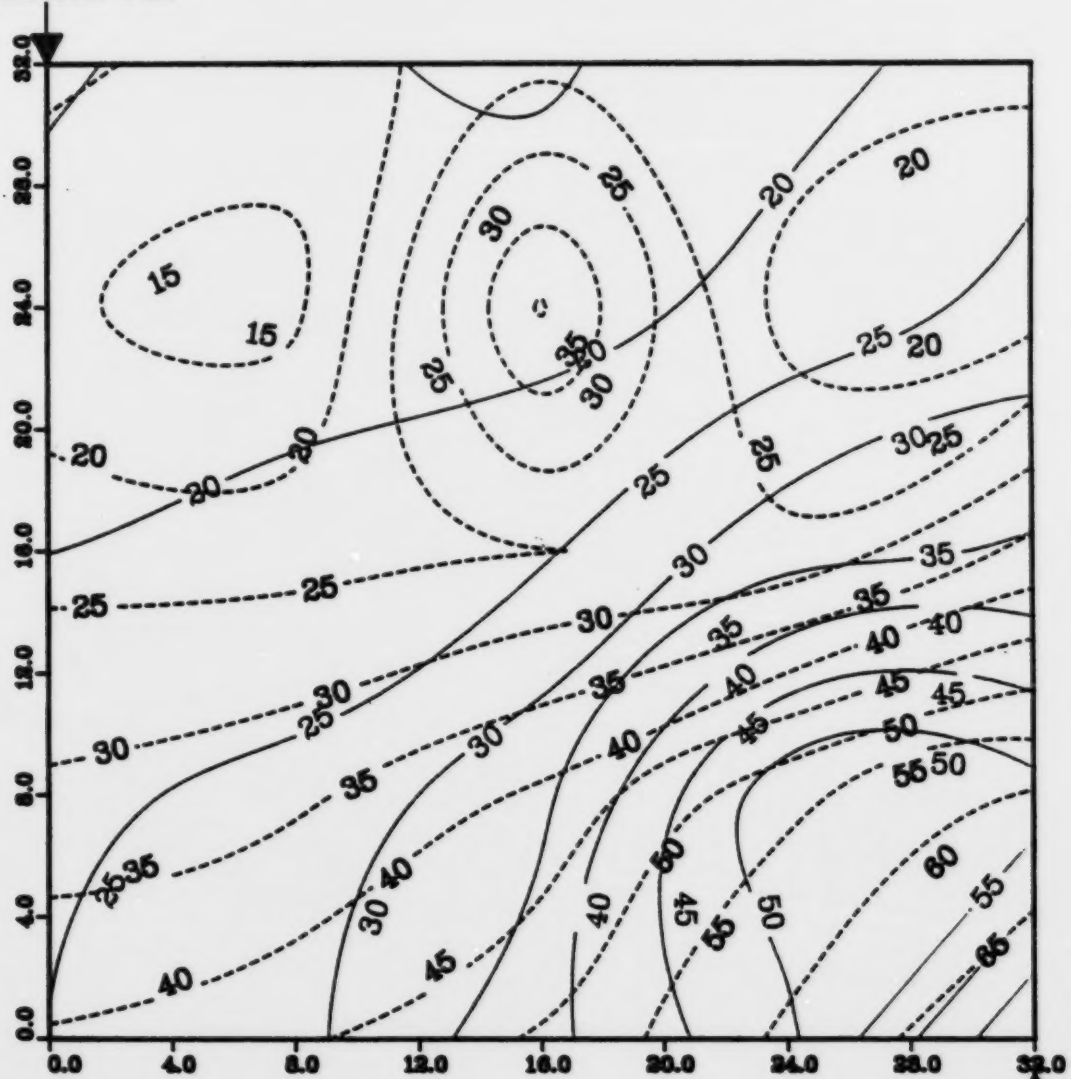


Figure A.195 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.196 : Run 56
Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
1.50 Pore Volumes Injected

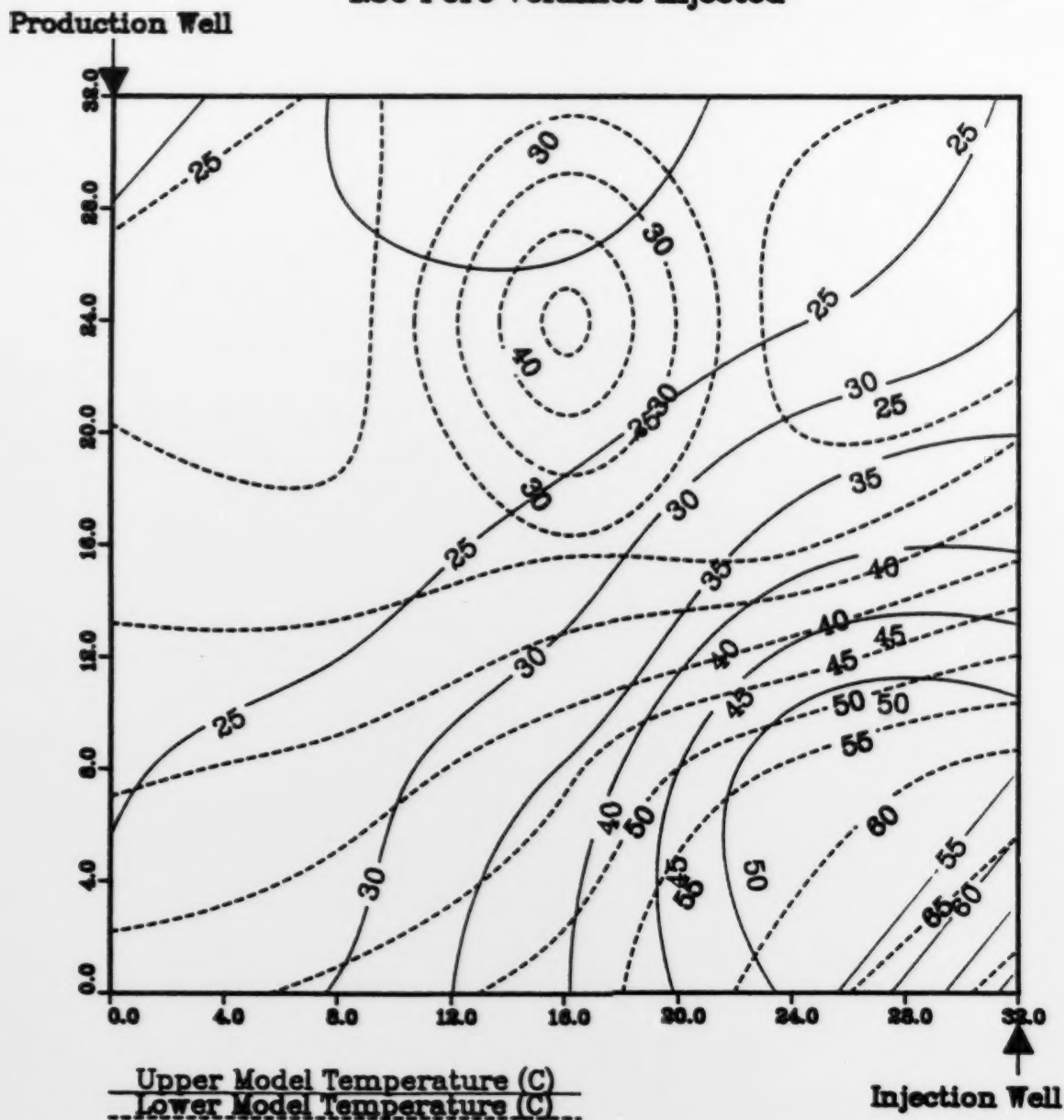


Figure A.197 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 1.75 Pore Volumes Injected

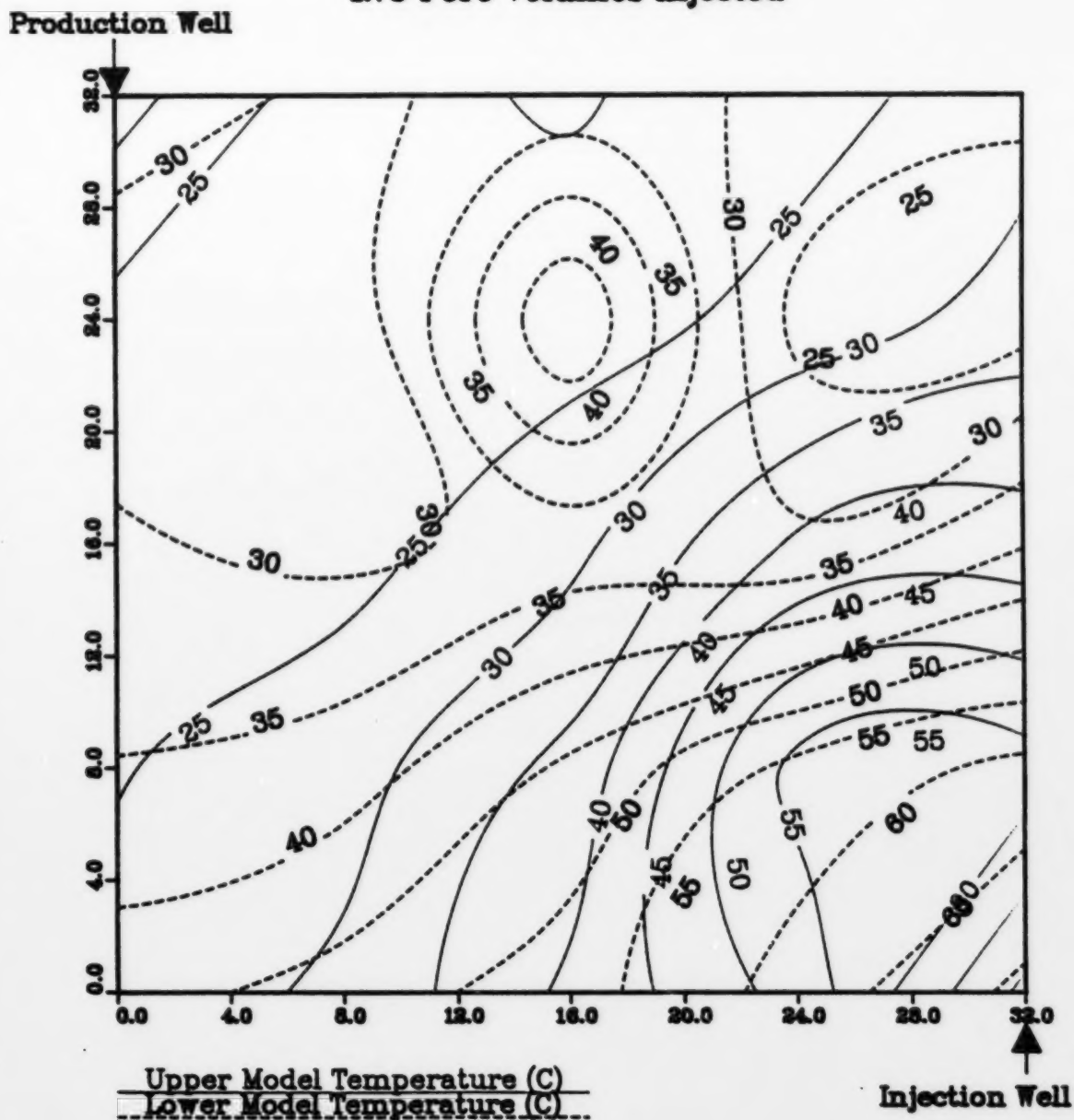


Figure A.198 : Run 56
 Gas Inj. Solv.-Stmflood in Homo. Model

Temperature Profile for
 2.00 Pore Volumes Injected

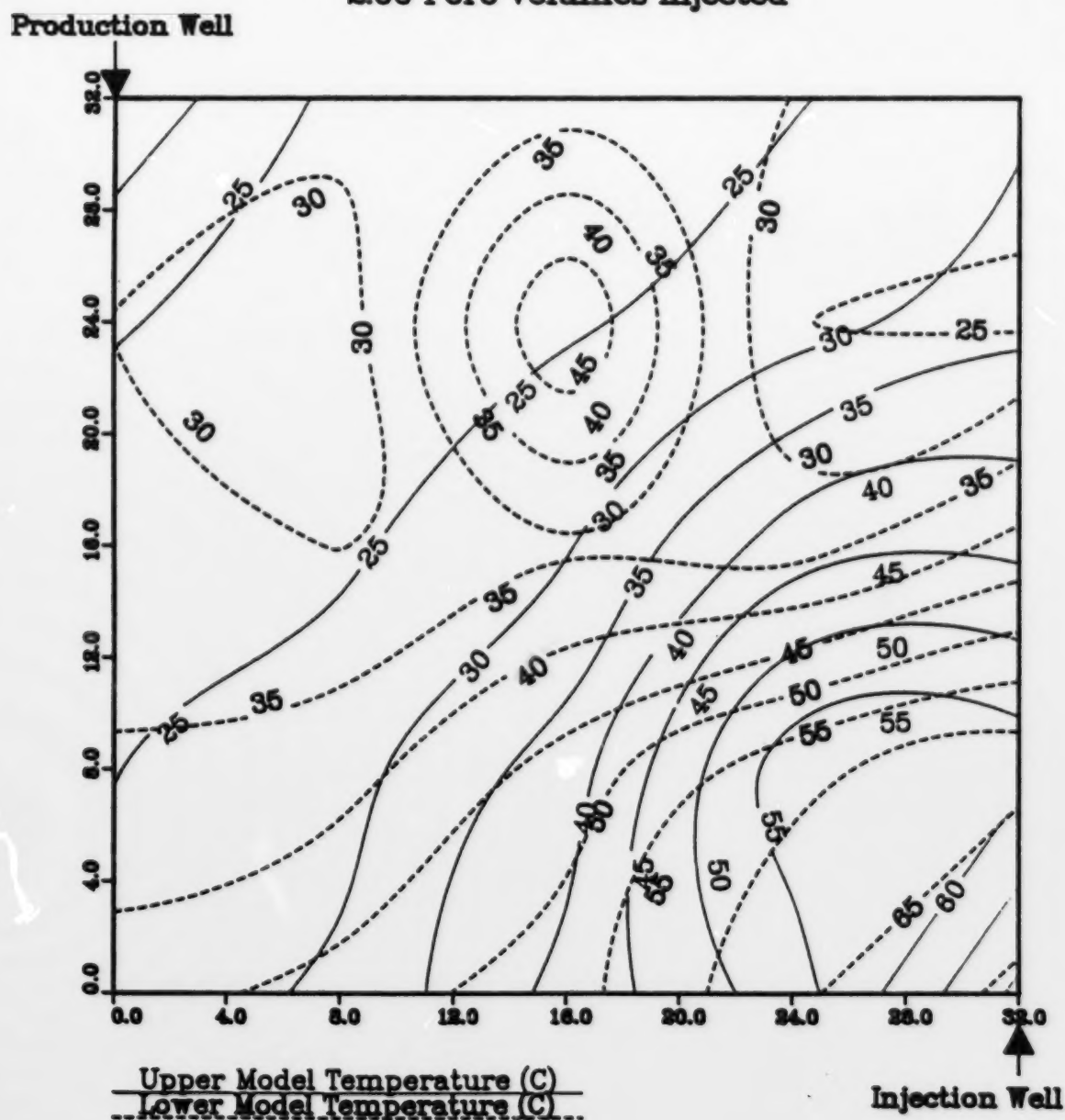


**Figure A.199 :Run 56 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

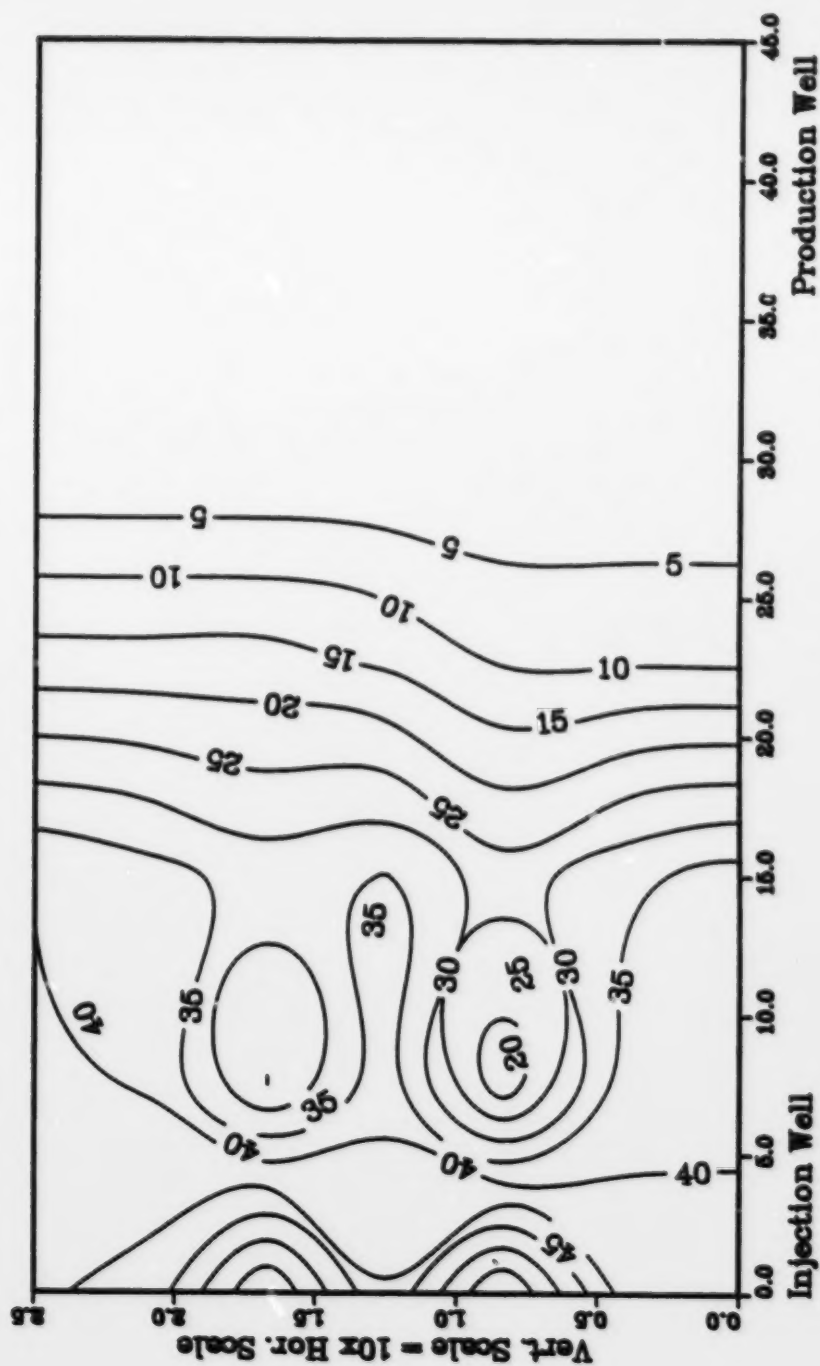


**Figure A.200 :Run 56 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

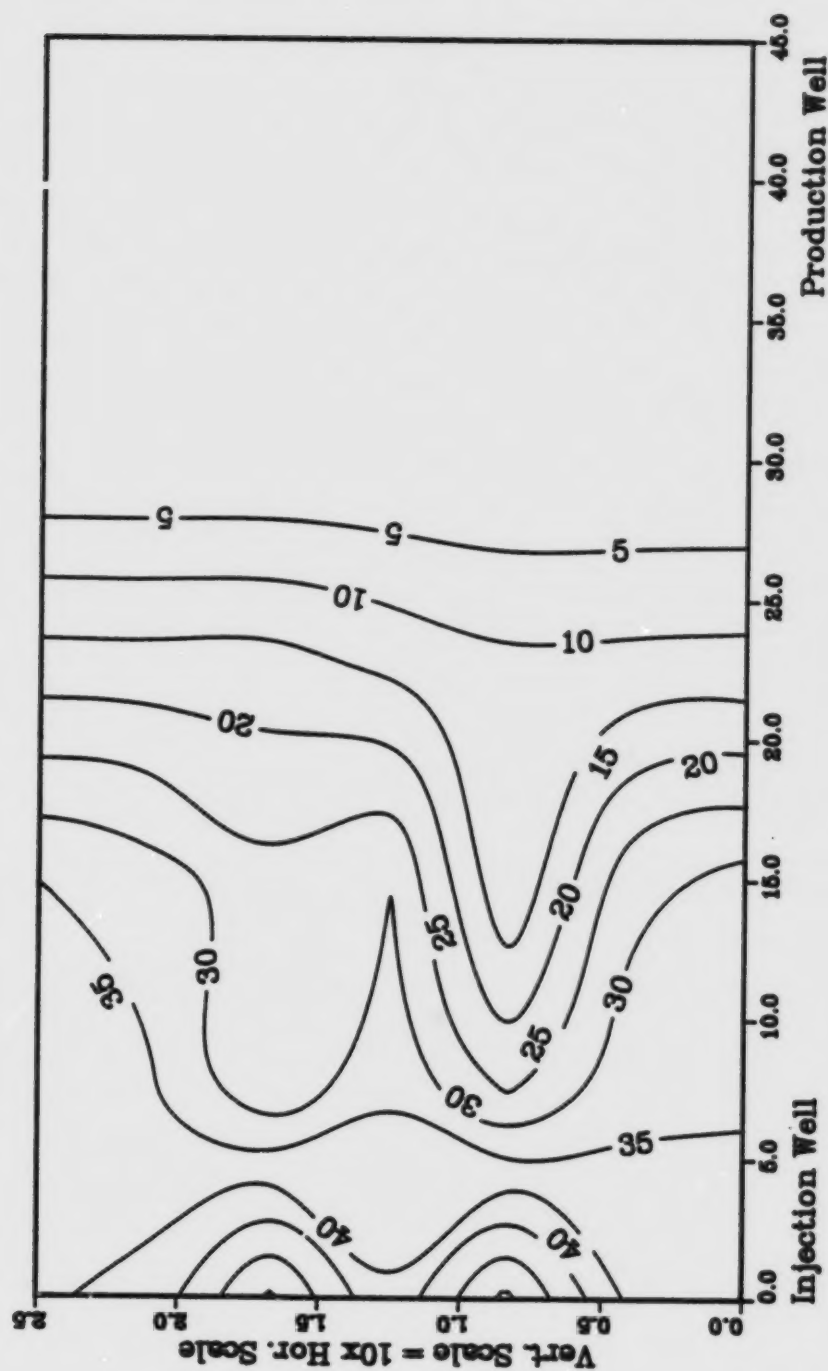


**Figure A.201 :Run 56 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

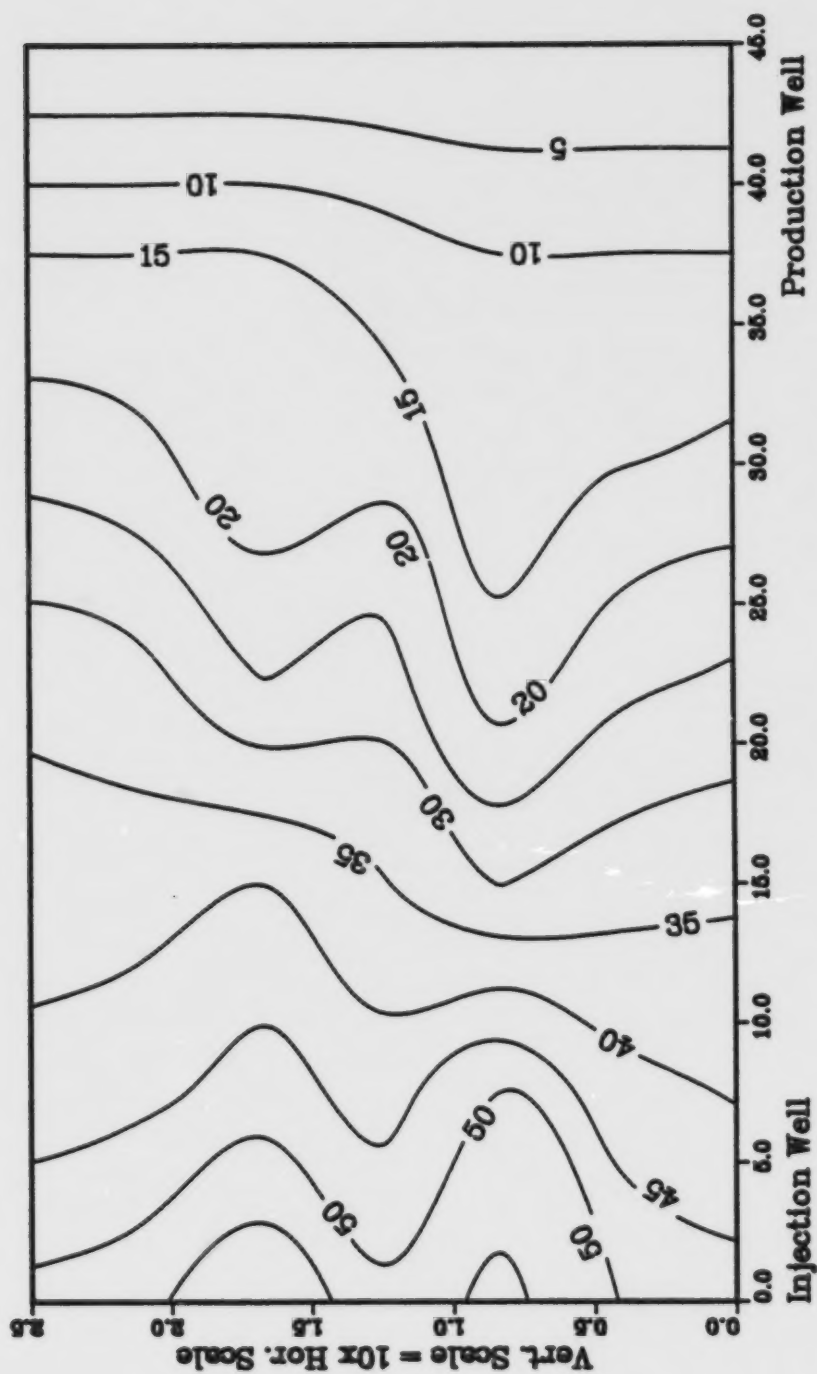


**Figure A.202 :Run 56 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

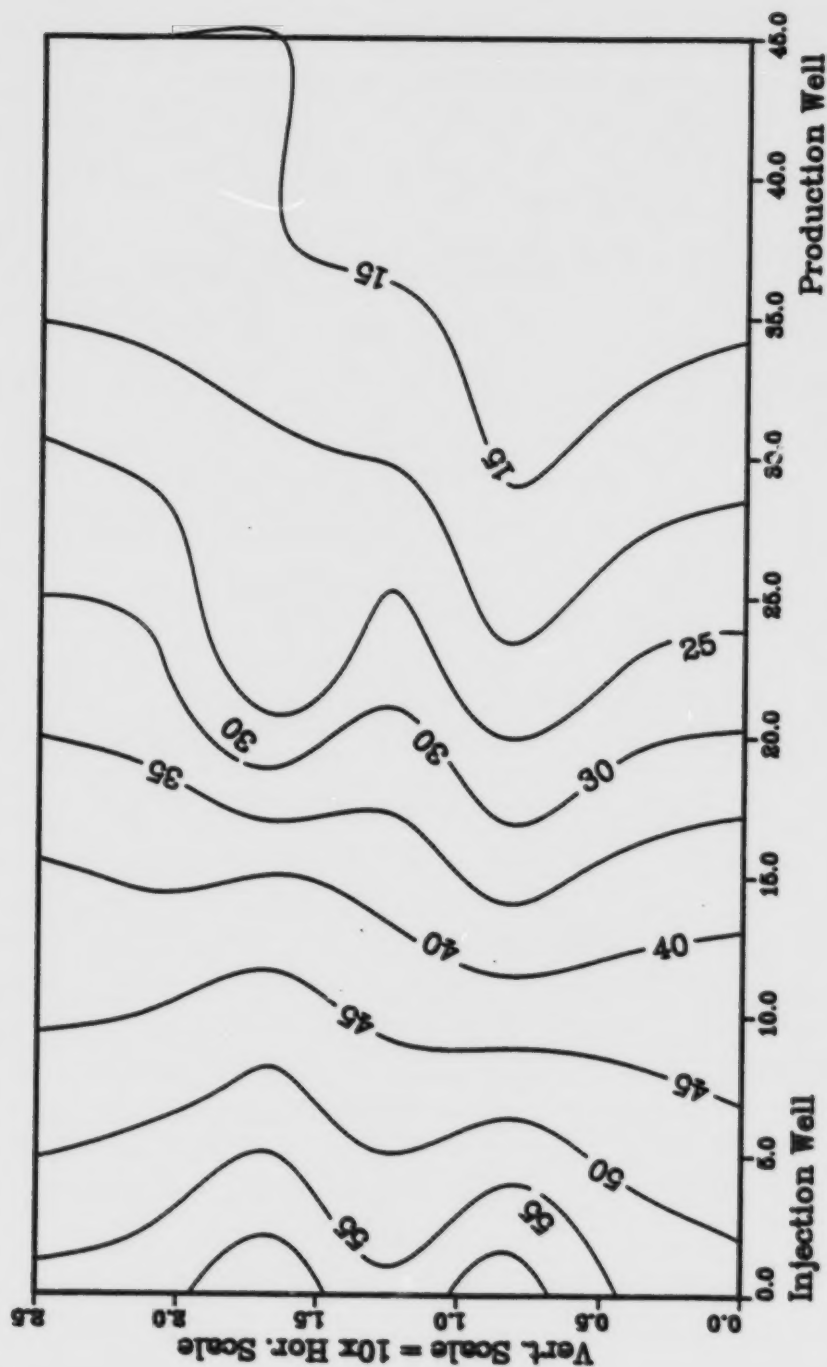


Figure A203 : Run 58
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.25 Pore Volumes Injected

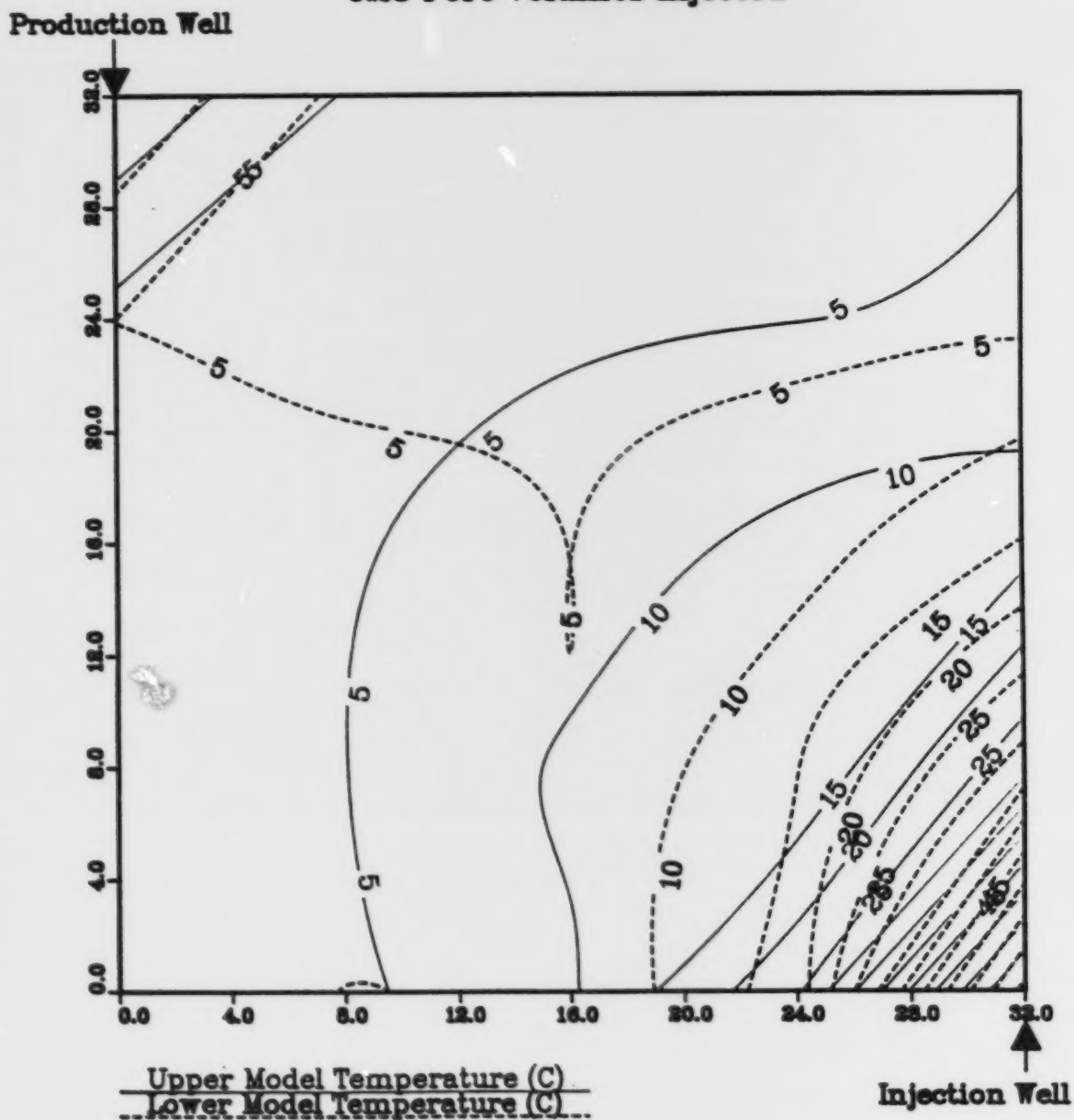


Figure A.204 : Run 58
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.50 Pore Volumes Injected

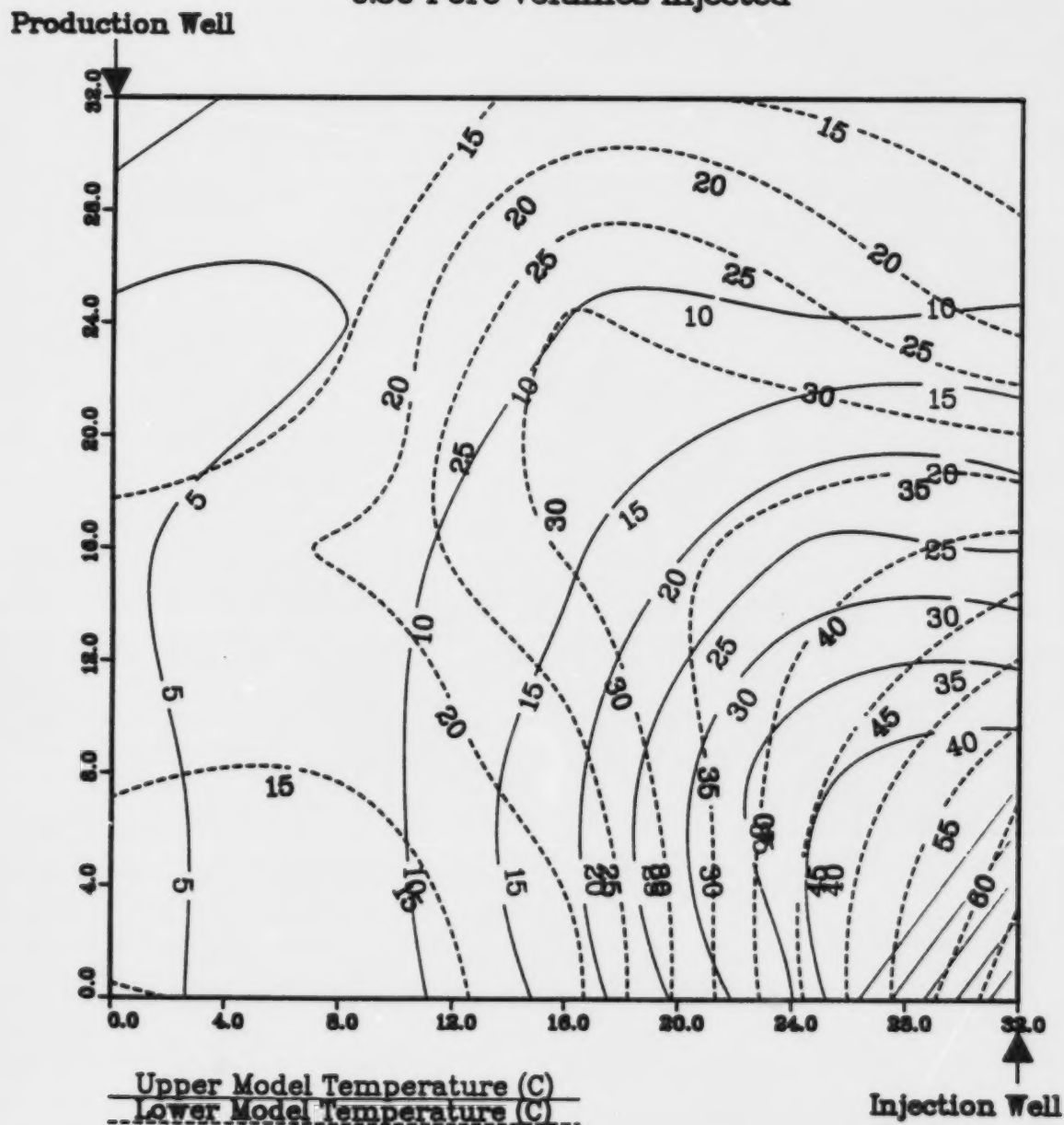
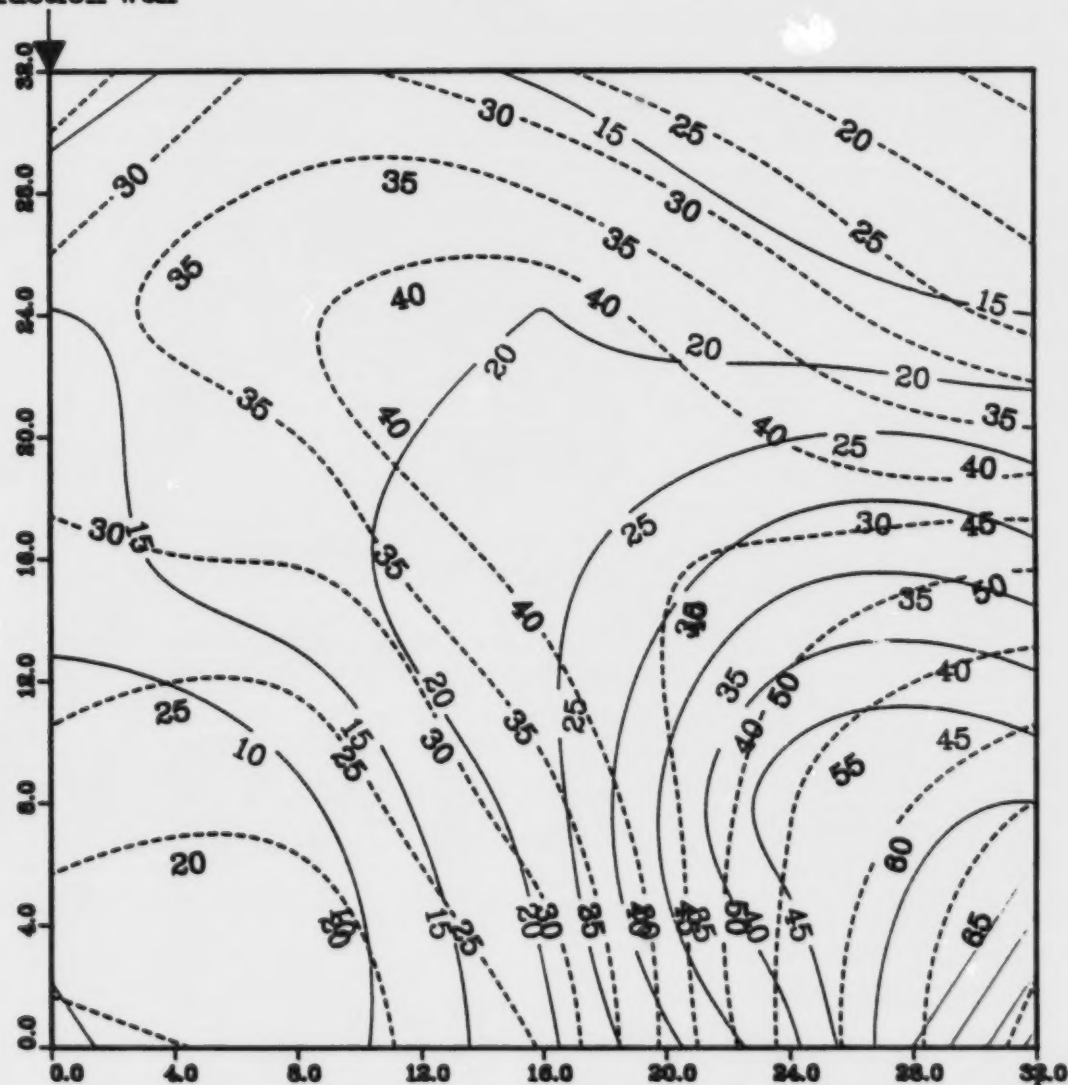


Figure A205 : Run 58
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A206 : Run 58
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

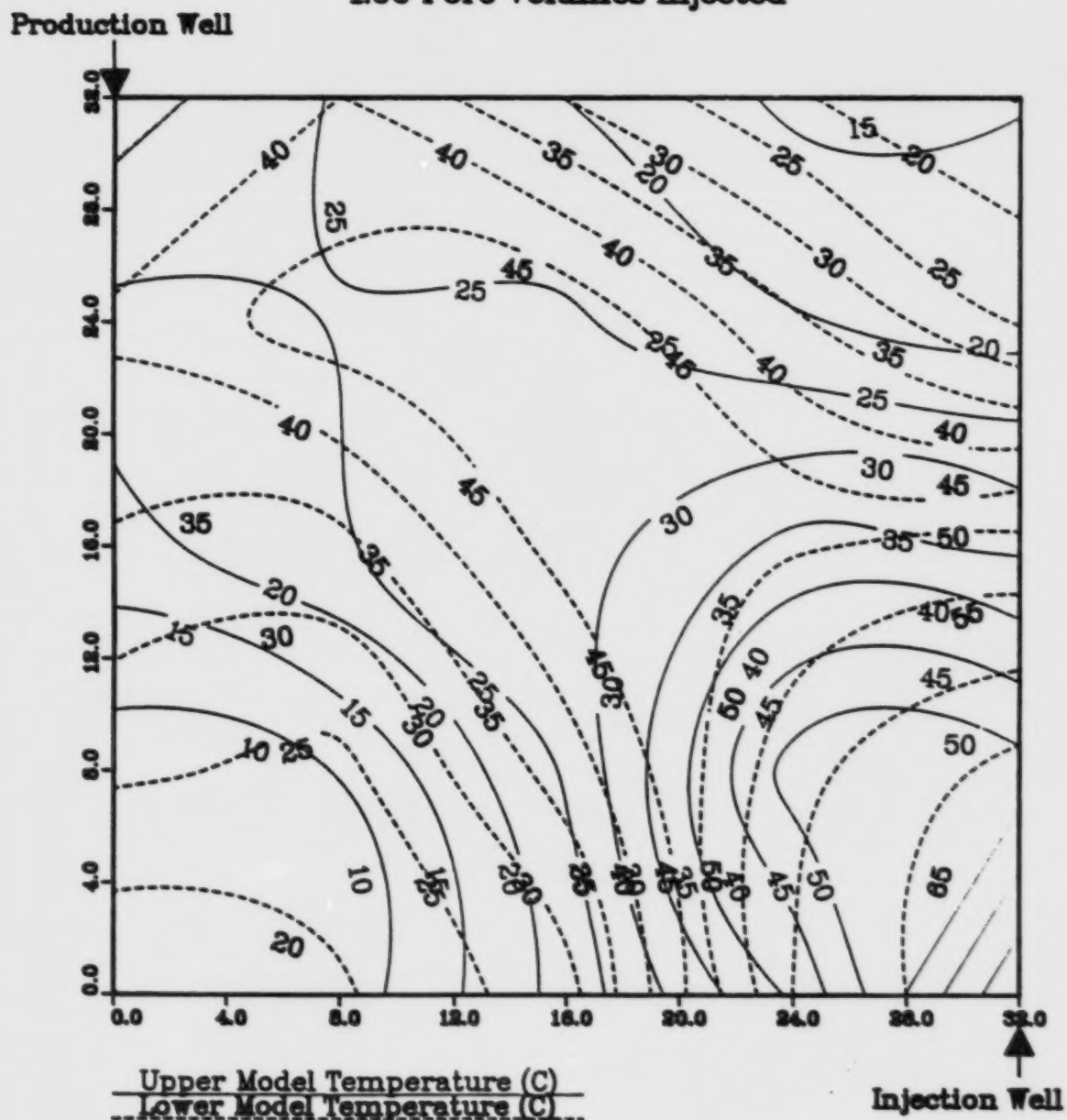


Figure A.207 : Run 58
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

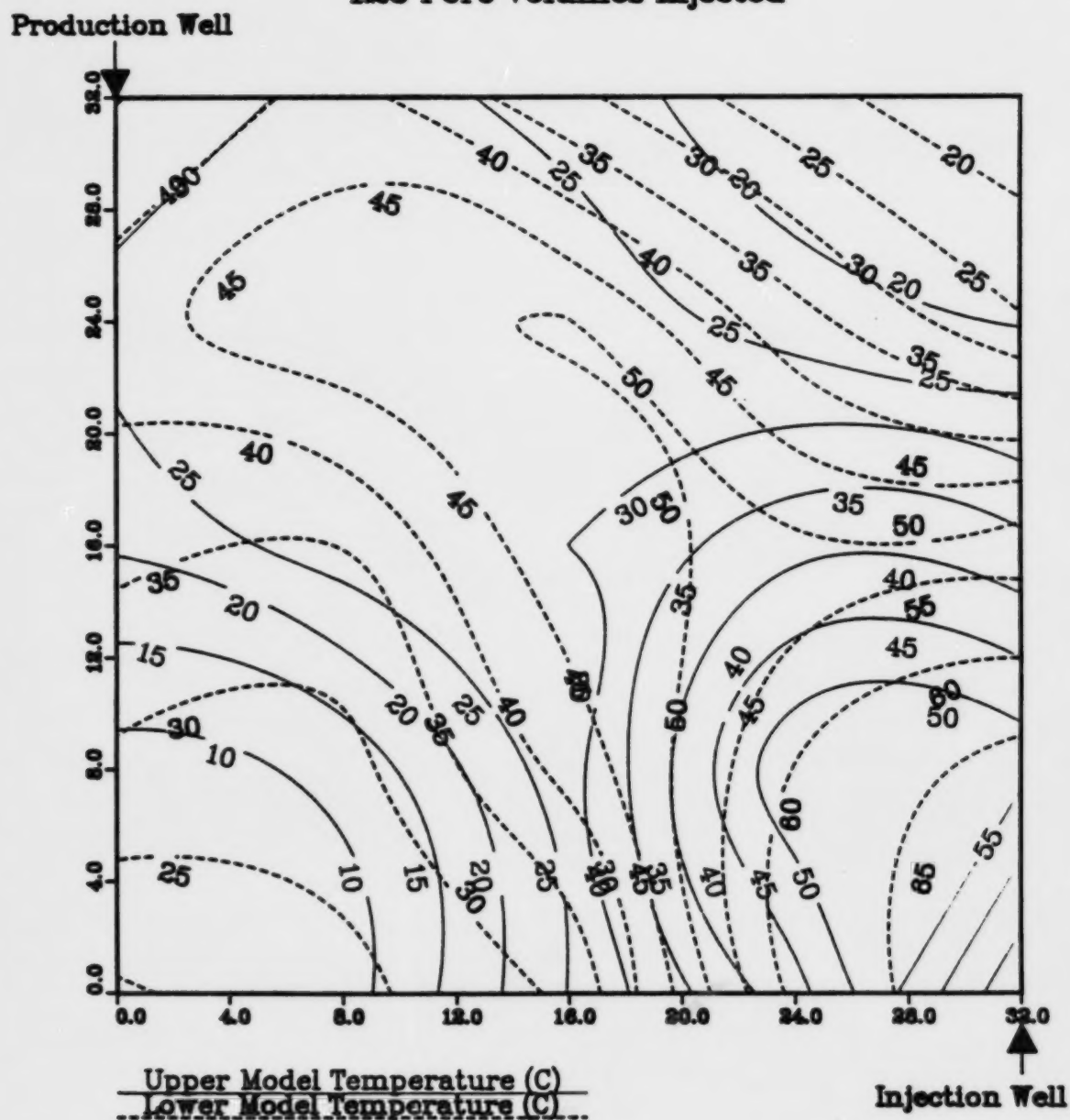


Figure A.208 : Run 58
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

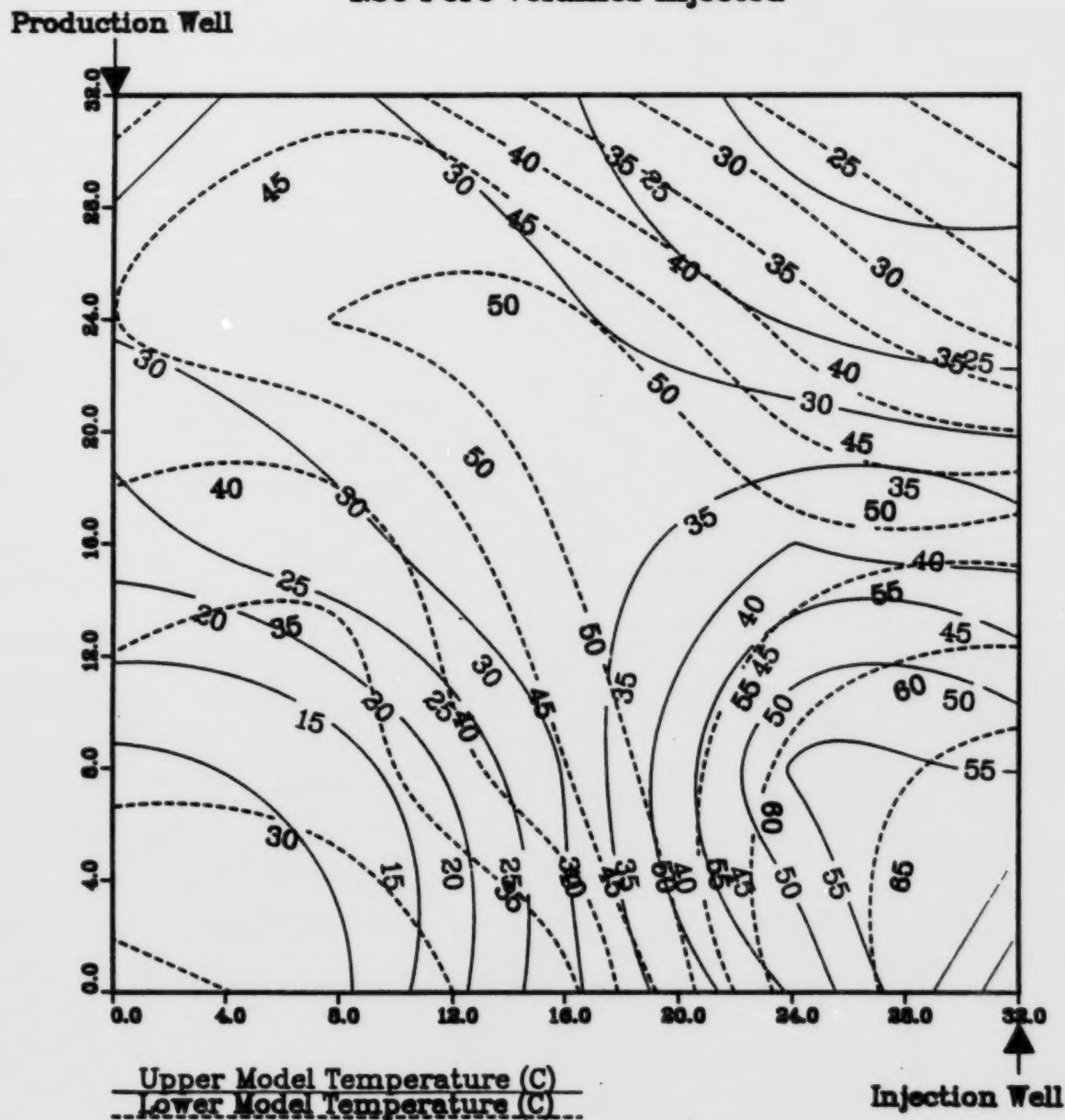


Figure A.209 : Run 58
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 1.75 Pore Volumes Injected

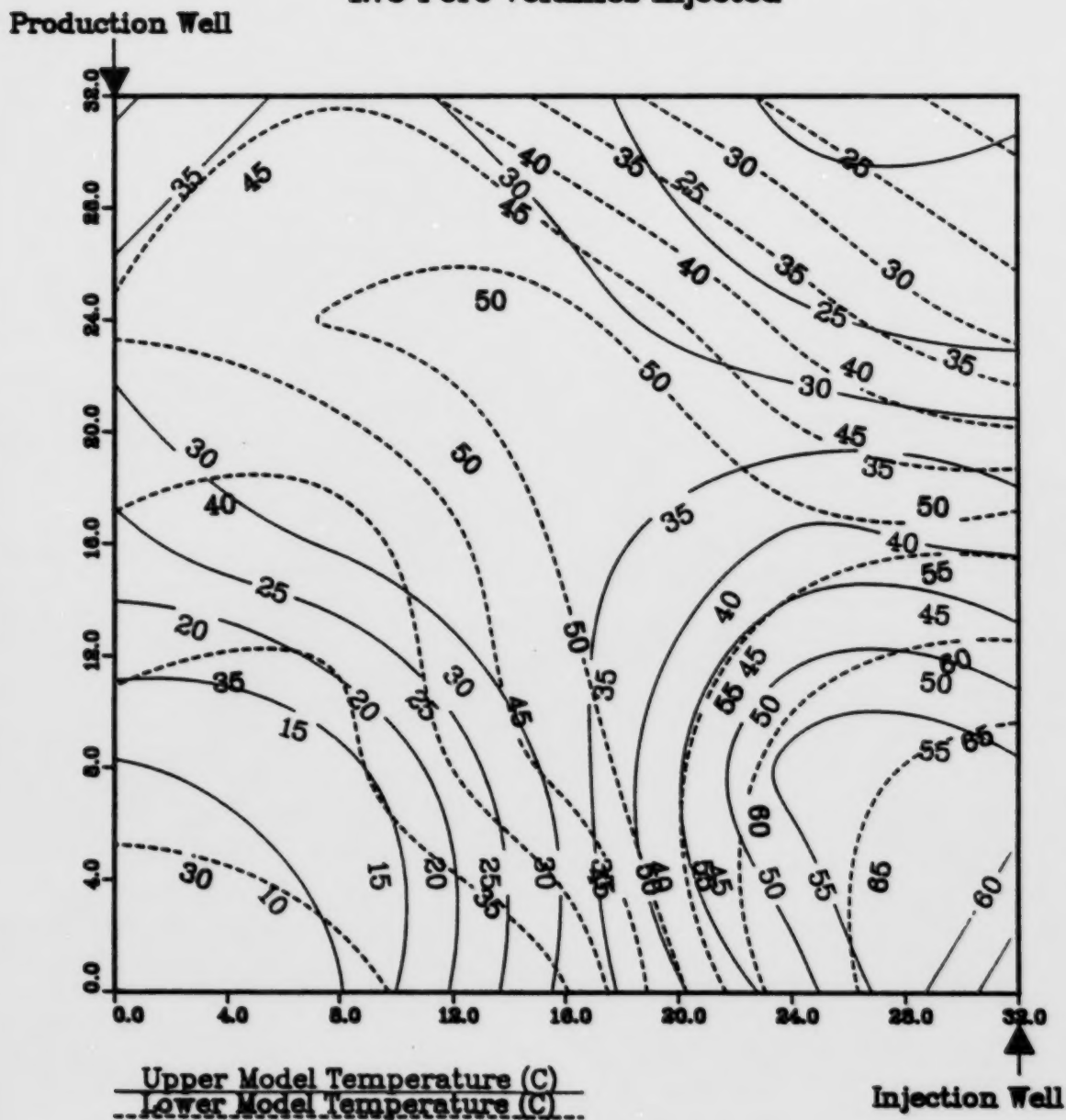


Figure A.210 : Run 58
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 2.00 Pore Volumes Injected

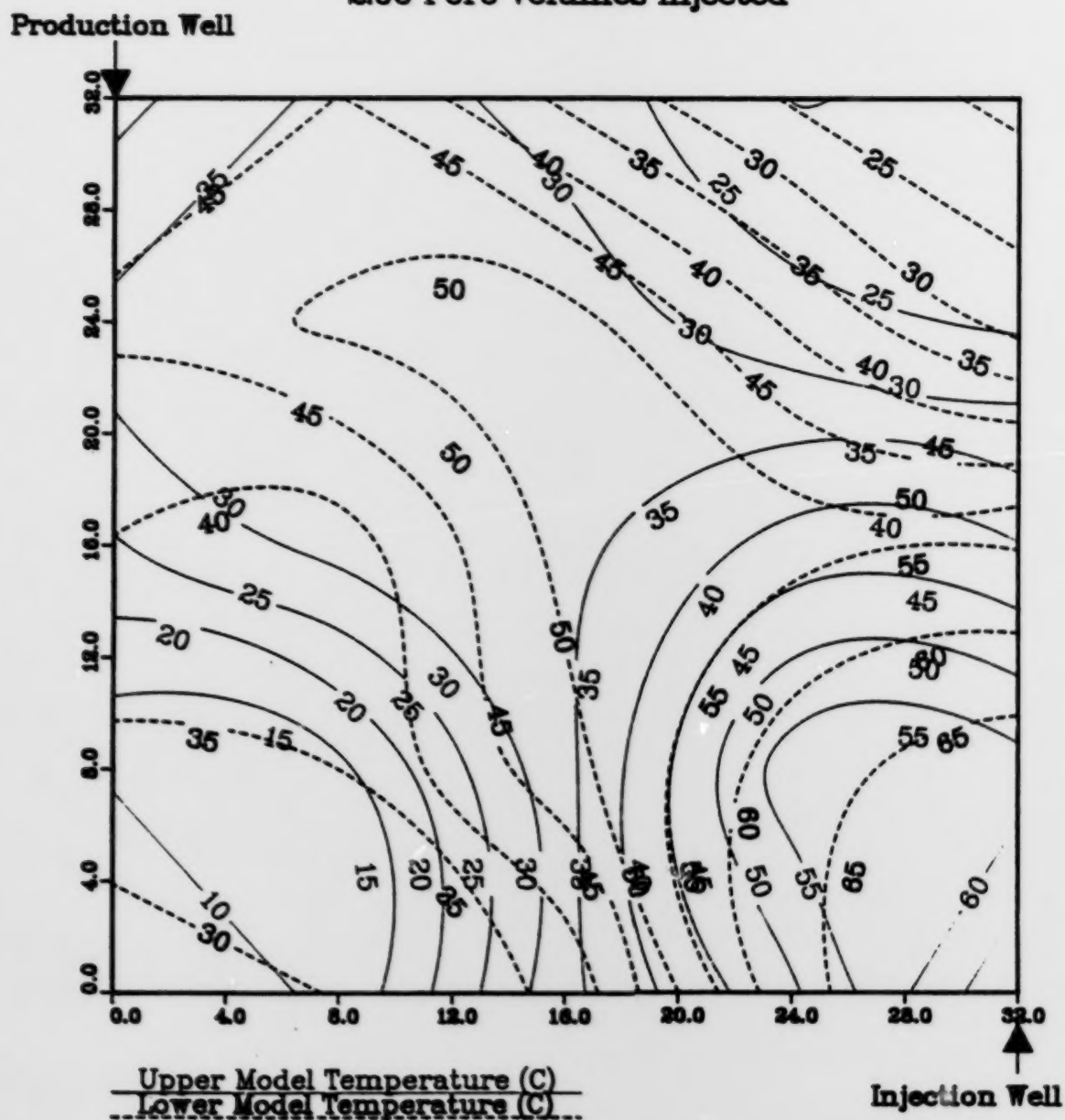


**Figure A.211 :Run 58 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

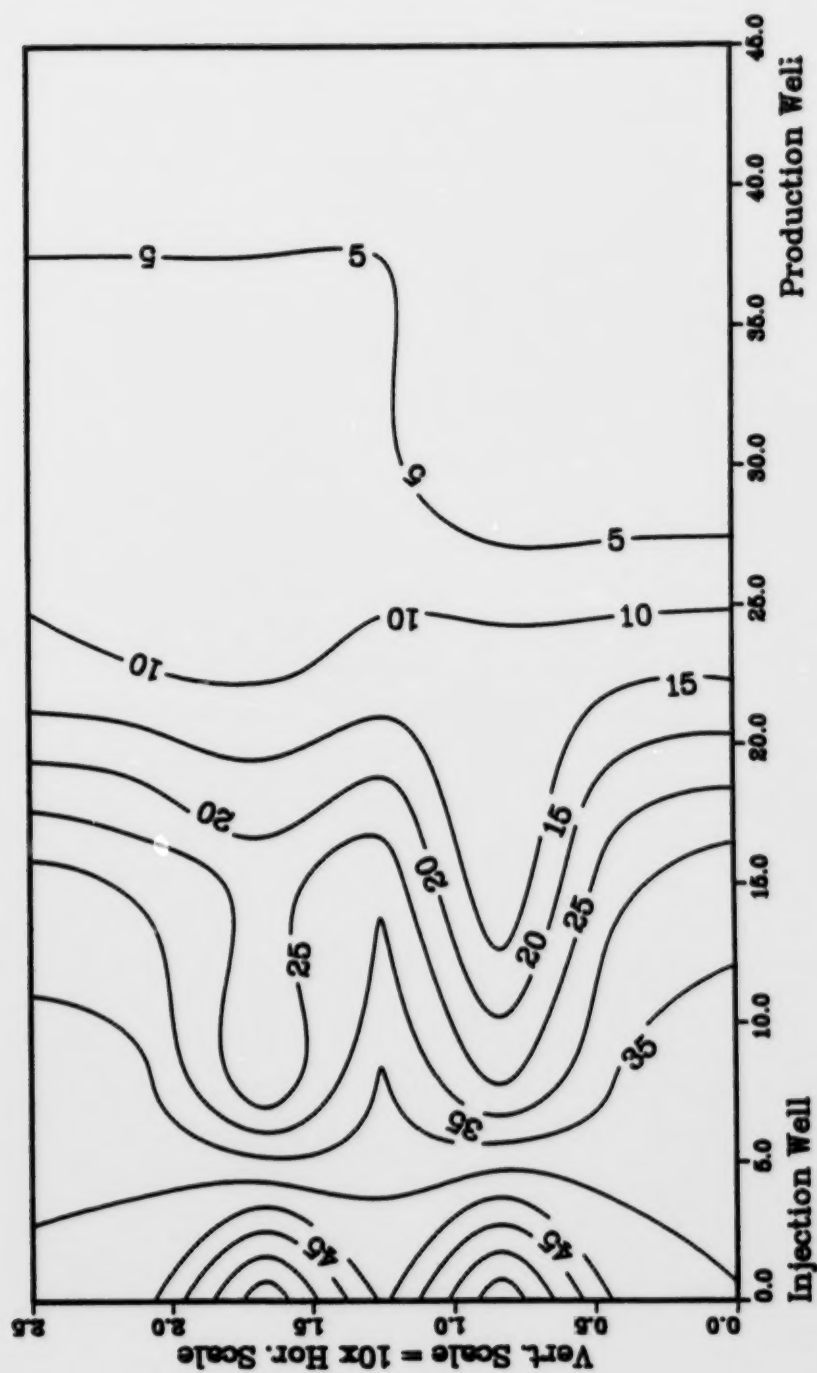


**Figure A.212: Run 58 Temp Profile
Injector to Producer Cross-Section**
0.50 Pore Volumes Injected.

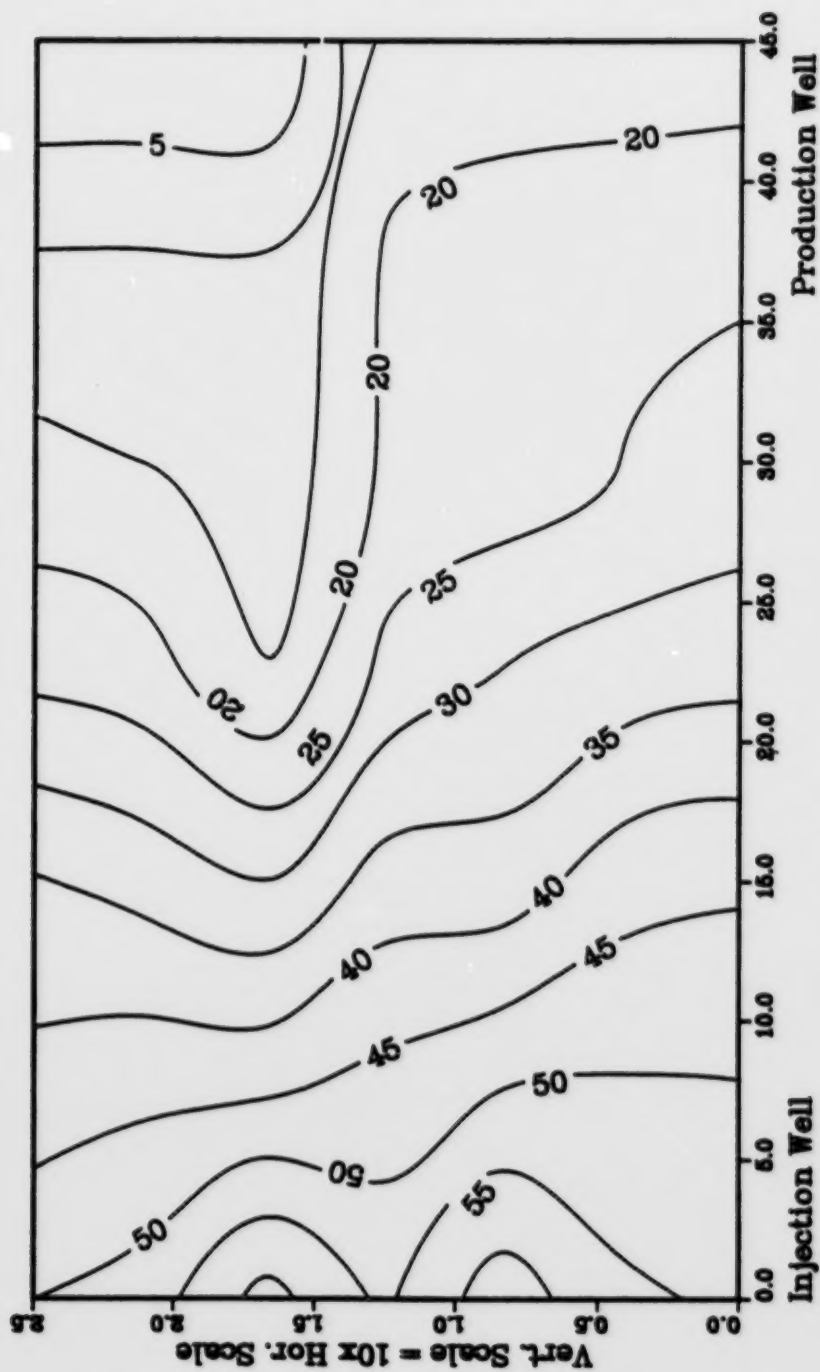


**Figure A.213 :Run 58 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

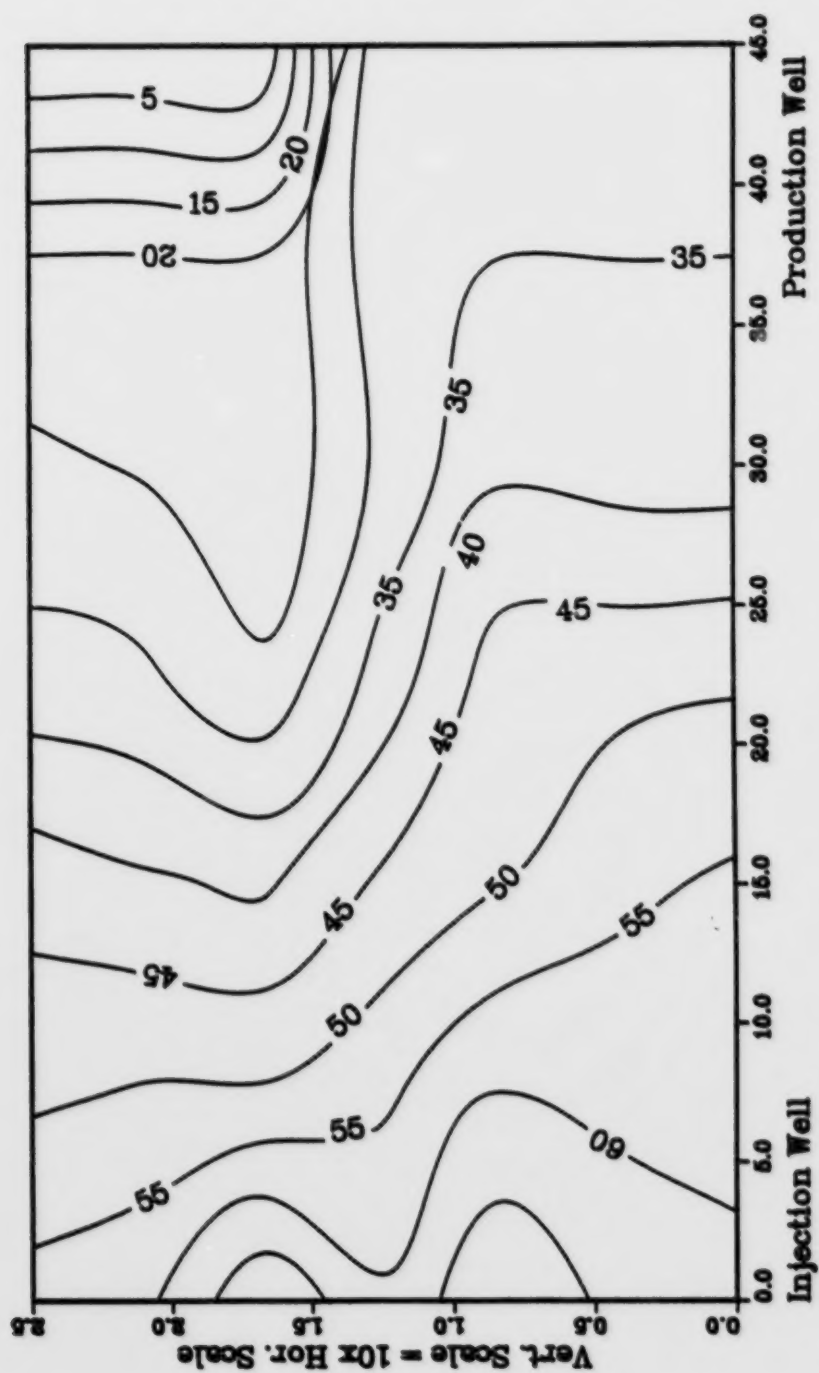


**Figure A.214 :Run 58 Temp Profile
Injector to Producer Cross-Section
1.00 Pore Volumes Injected.**

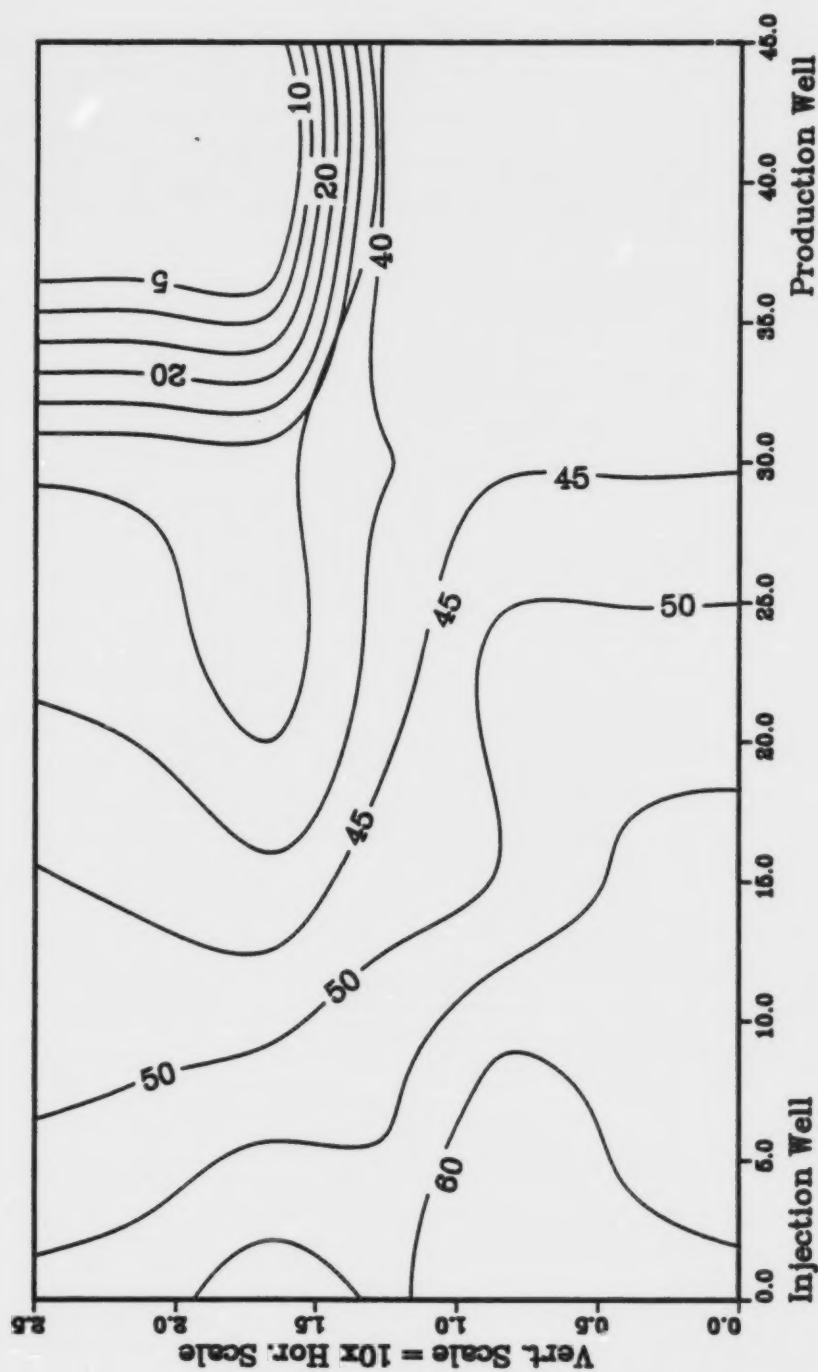
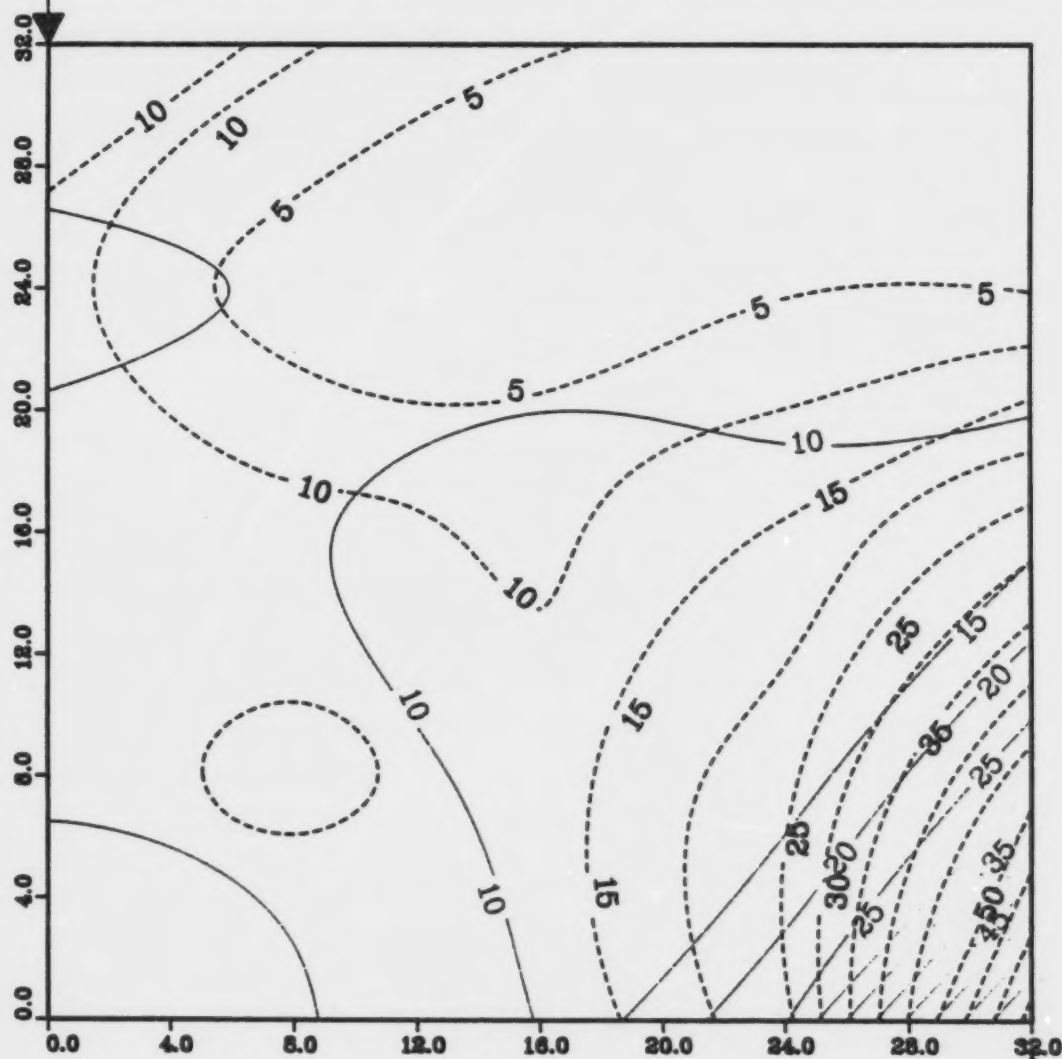


Figure A.215 : Run 59
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.216 : Run 59
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
0.50 Pore Volumes Injected

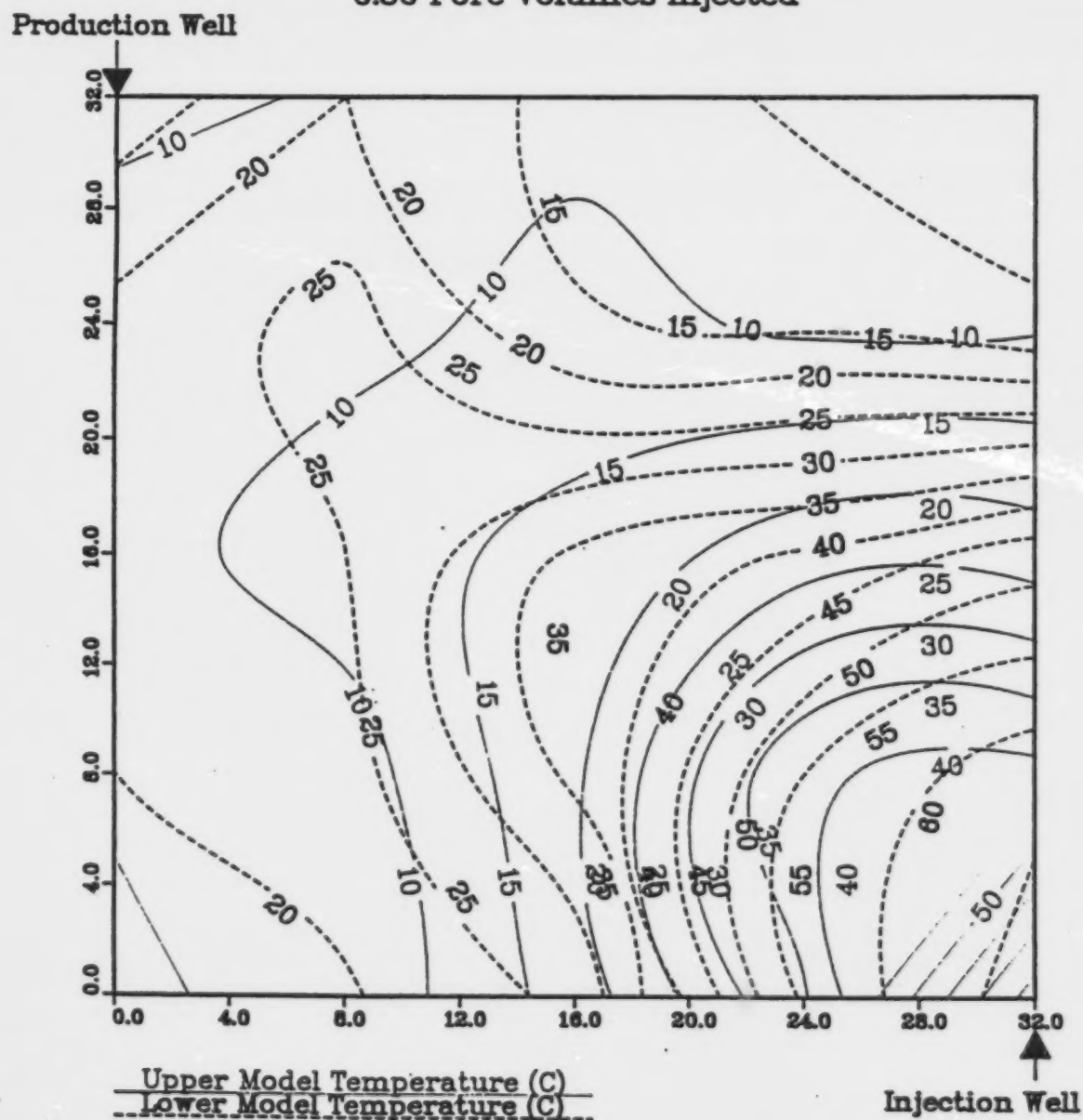
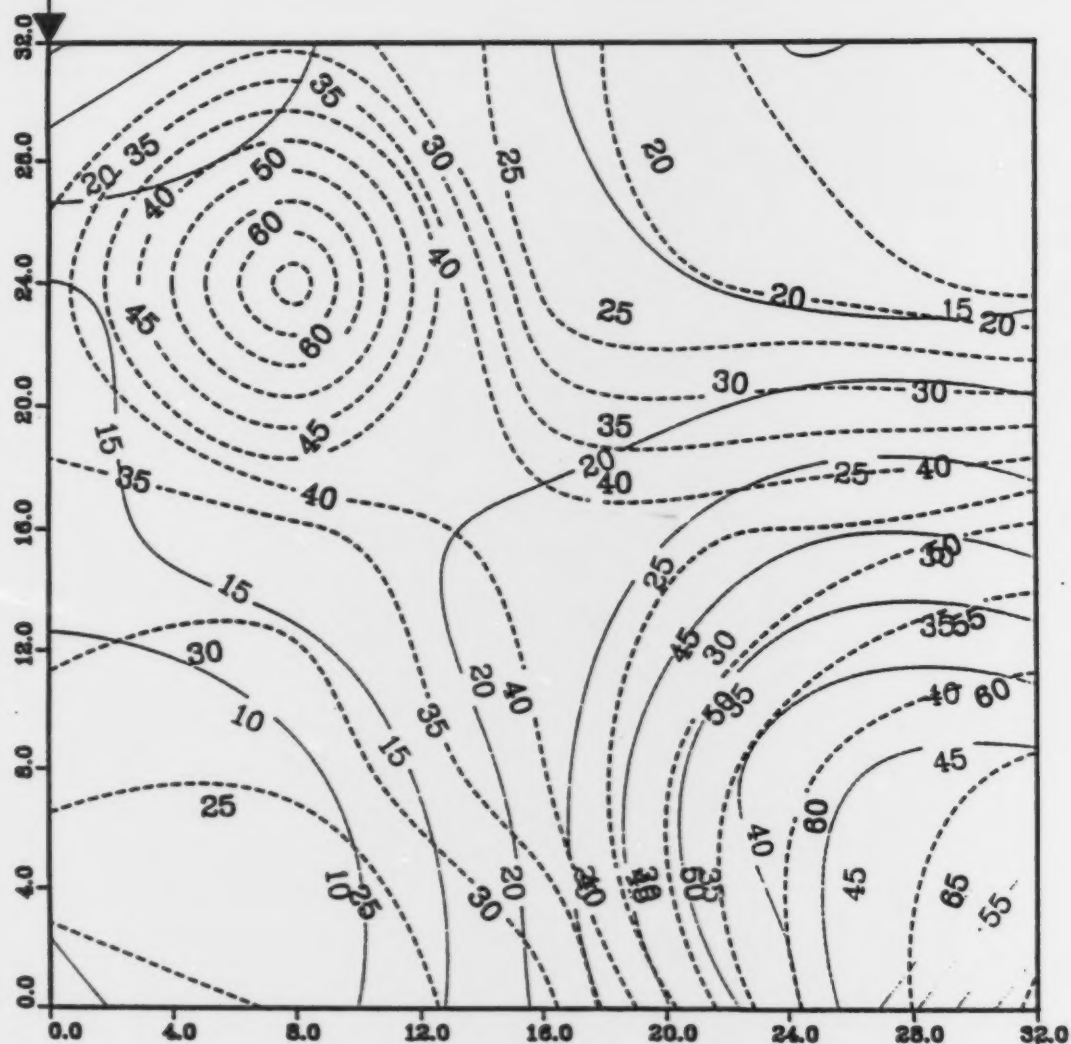


Figure A217 : Run 59
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

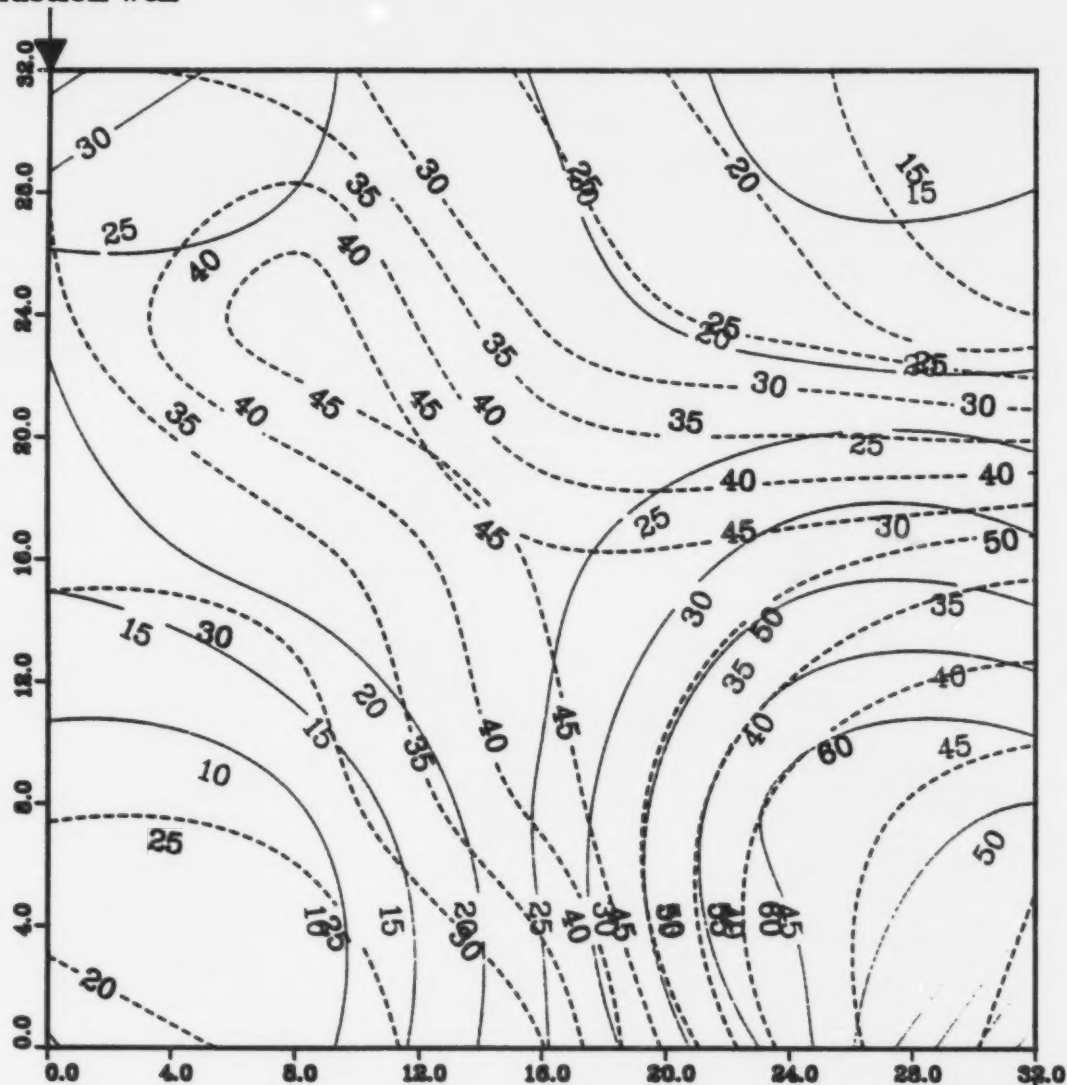
Lower Model Temperature (C)

Injection Well

Figure A.218 : Run 59
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

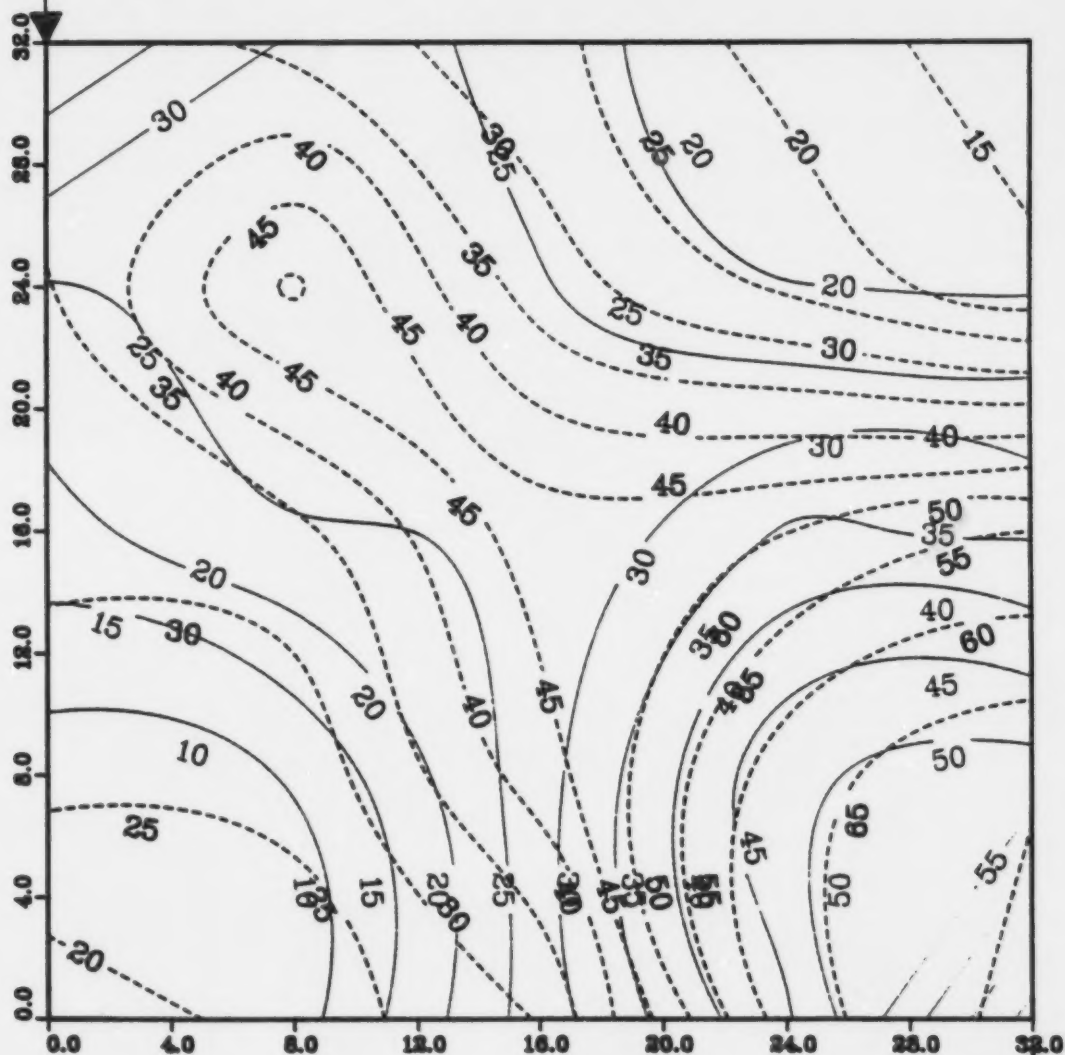
Lower Model Temperature (C)

Injection Well

Figure A219 : Run 59
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

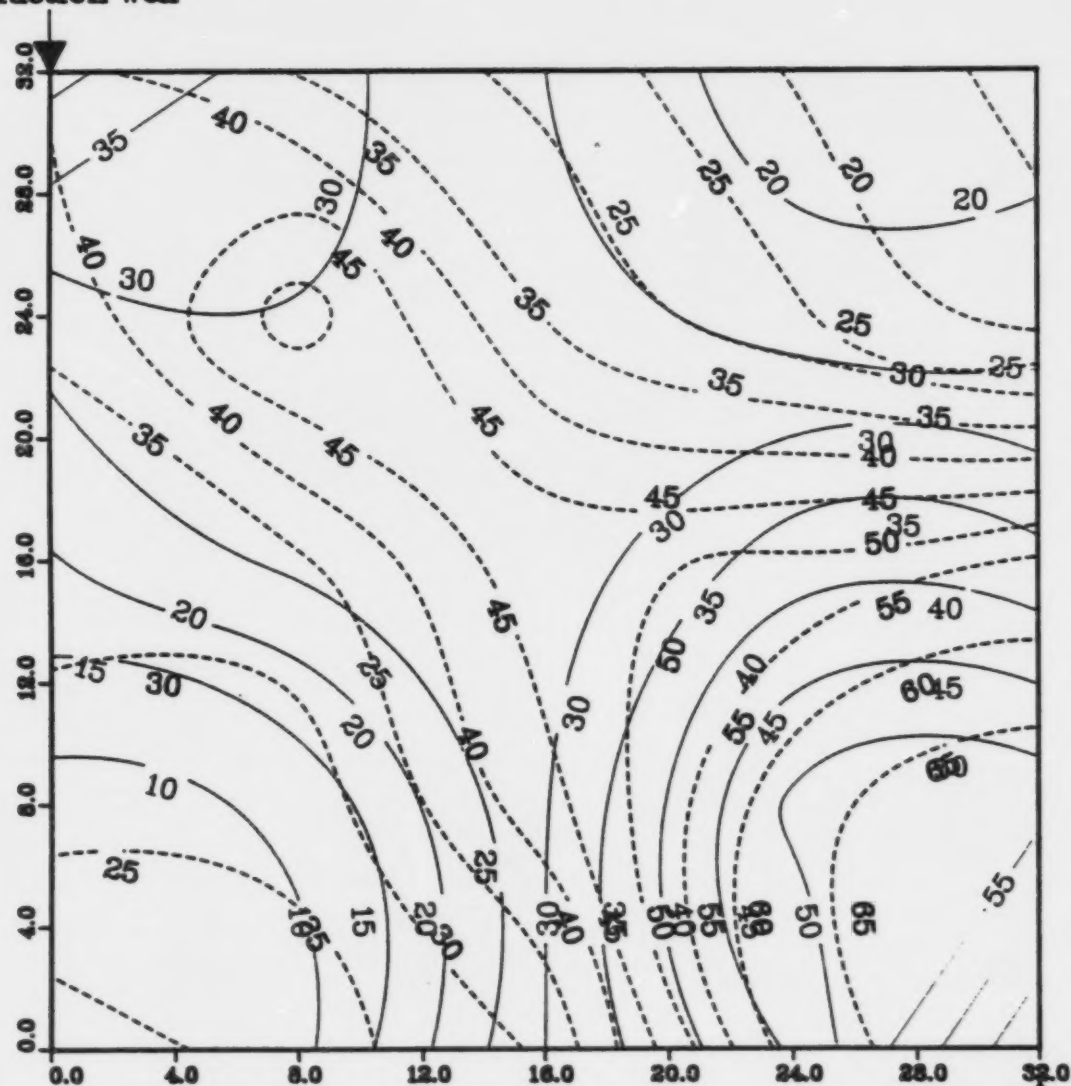
Lower Model Temperature (C)

Injection Well

Figure A.220 : Run 59
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.221 : Run 59
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 1.75 Pore Volumes Injected

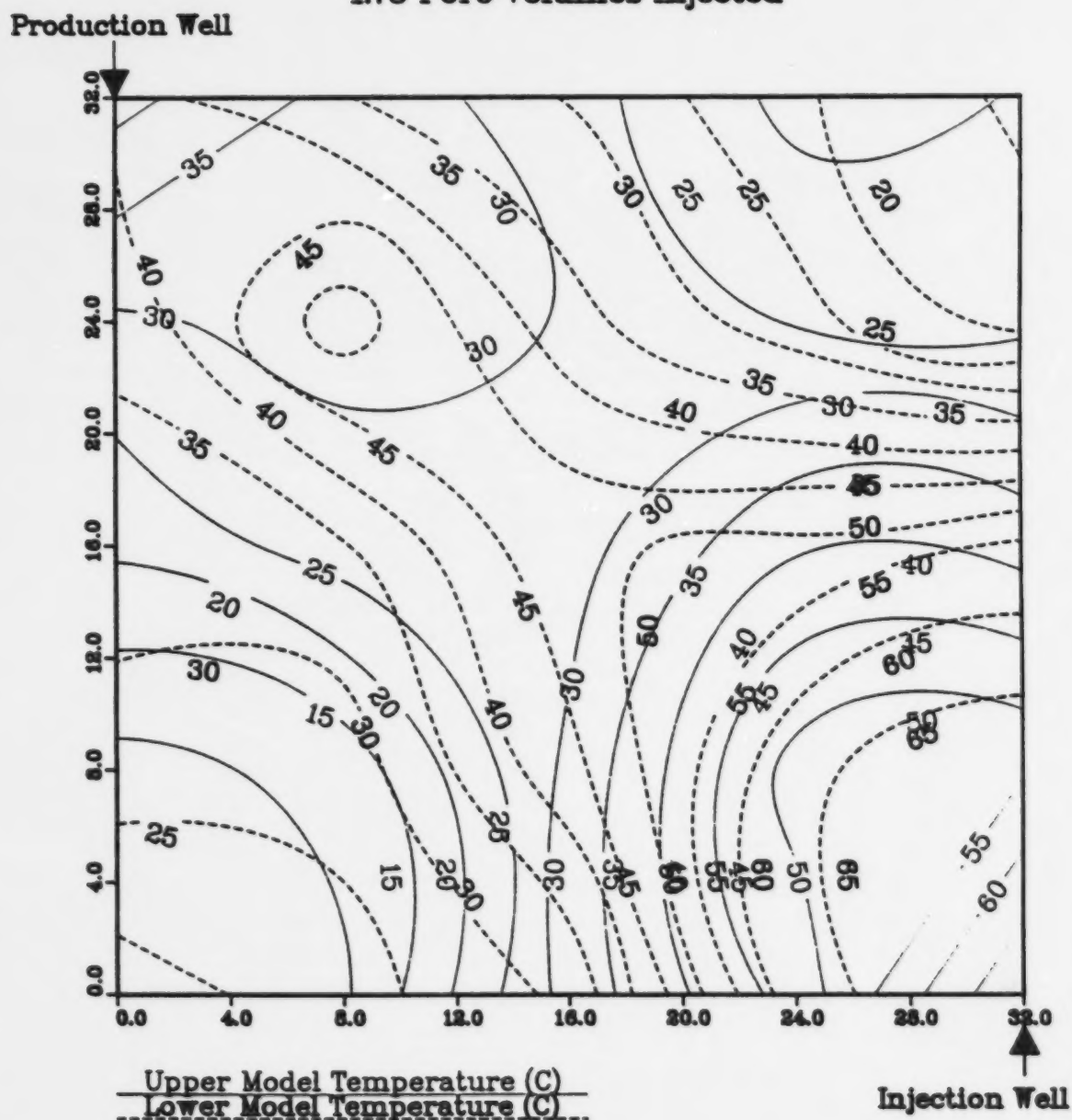


Figure A.222 : Run 59
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 2.00 Pore Volumes Injected

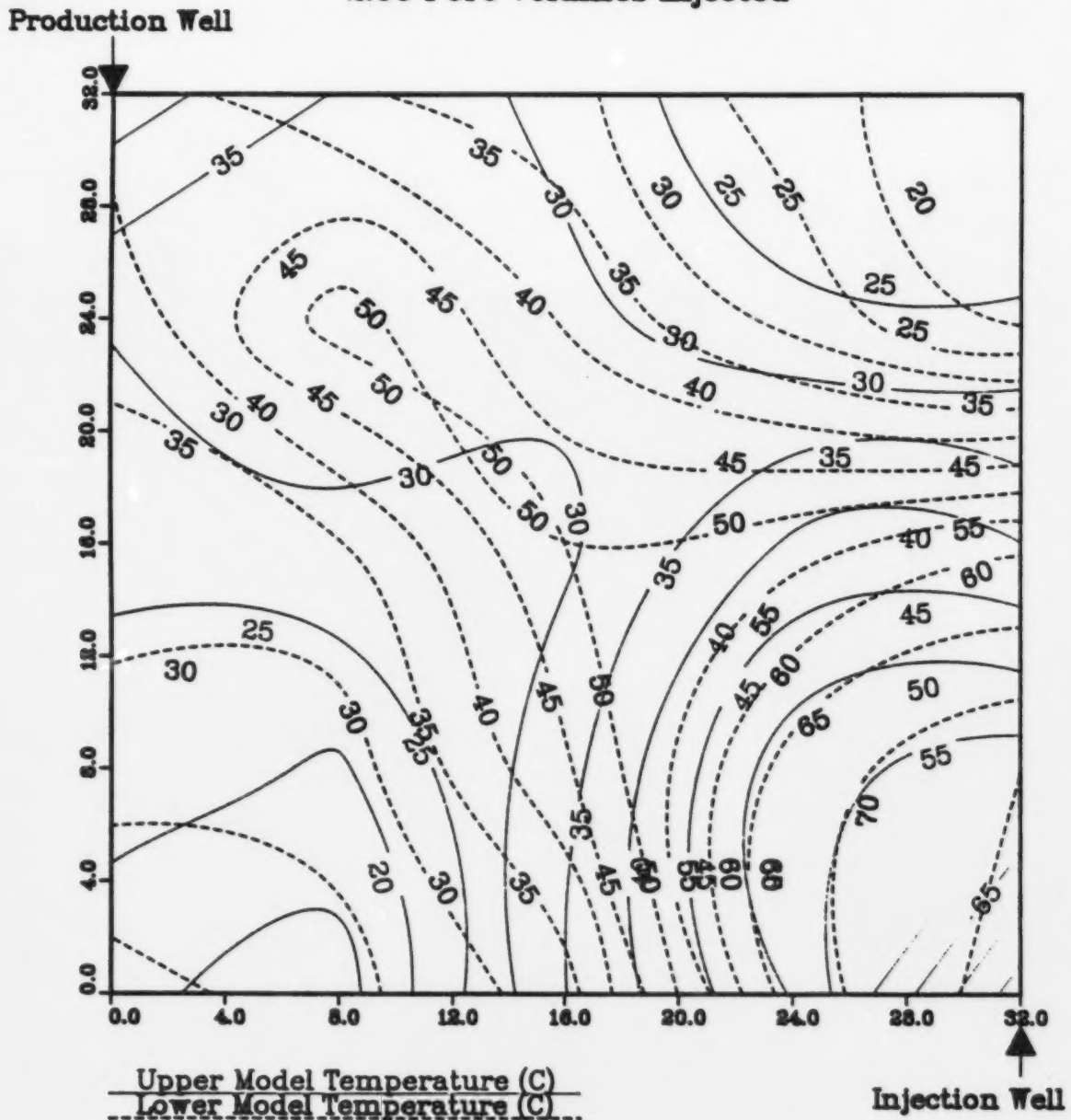


**Figure A.223: Run 59 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

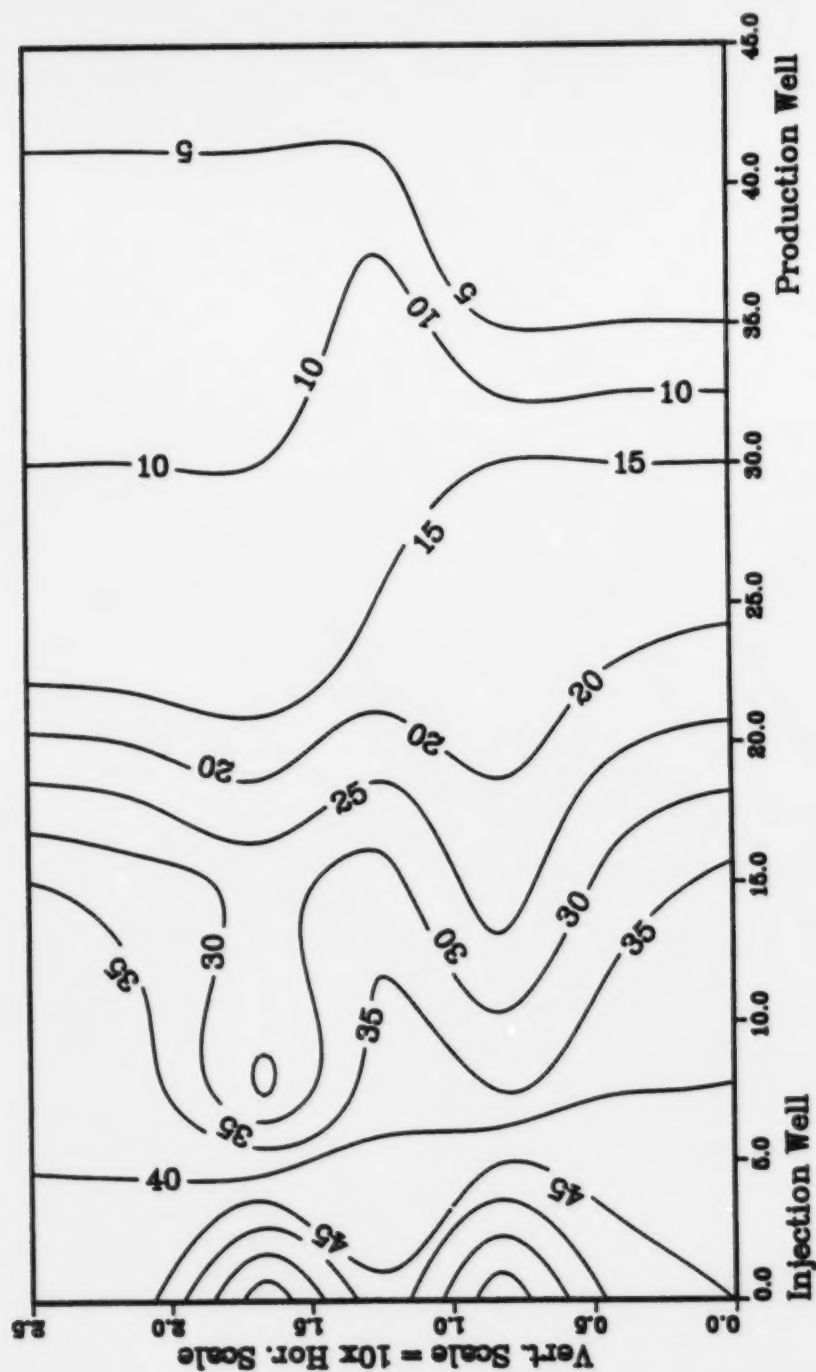


**Figure A.224 :Run 59 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

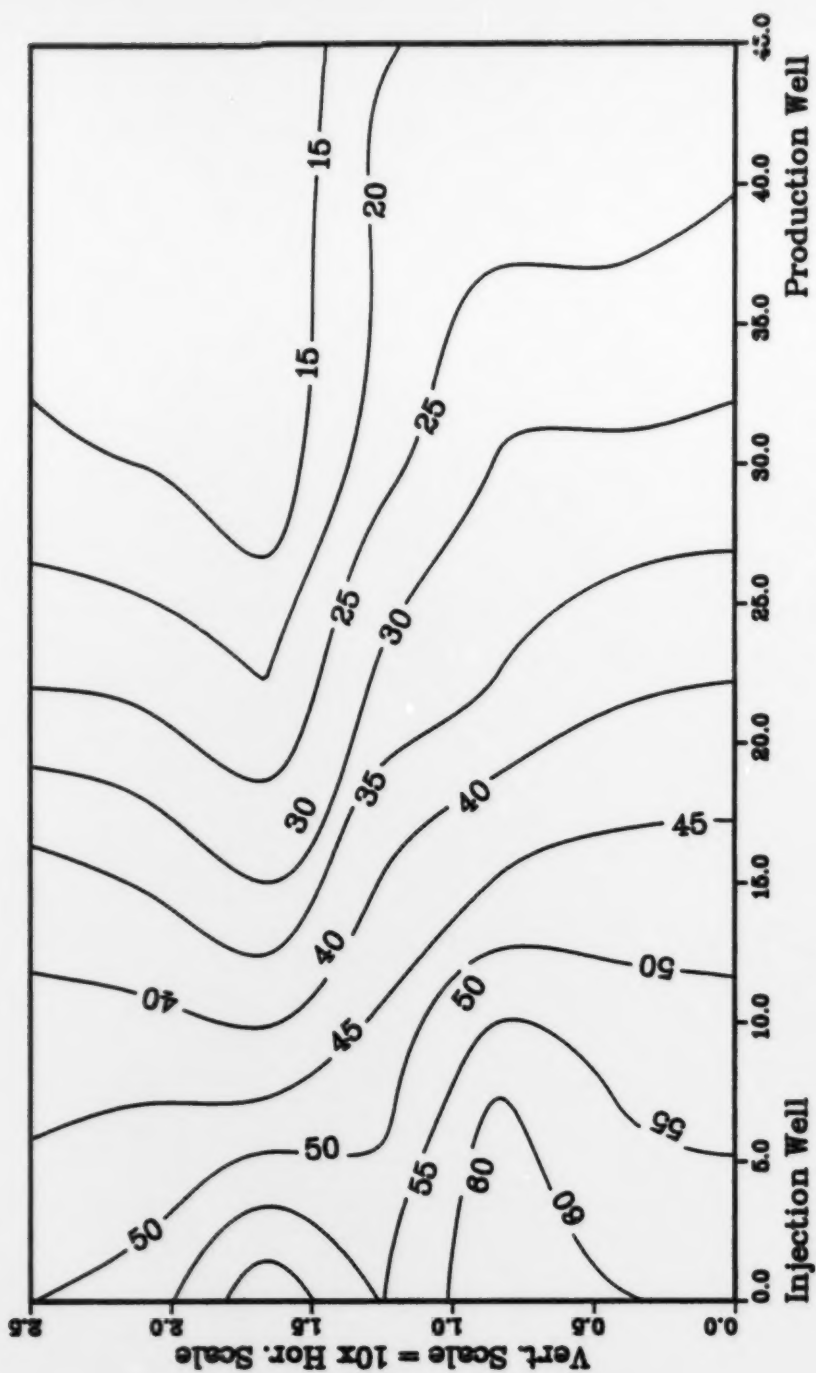


**Figure A.225 :Run 59 Temp Profile
Injector to Producer Cross-Section
0.75 Pore Volumes Injected.**

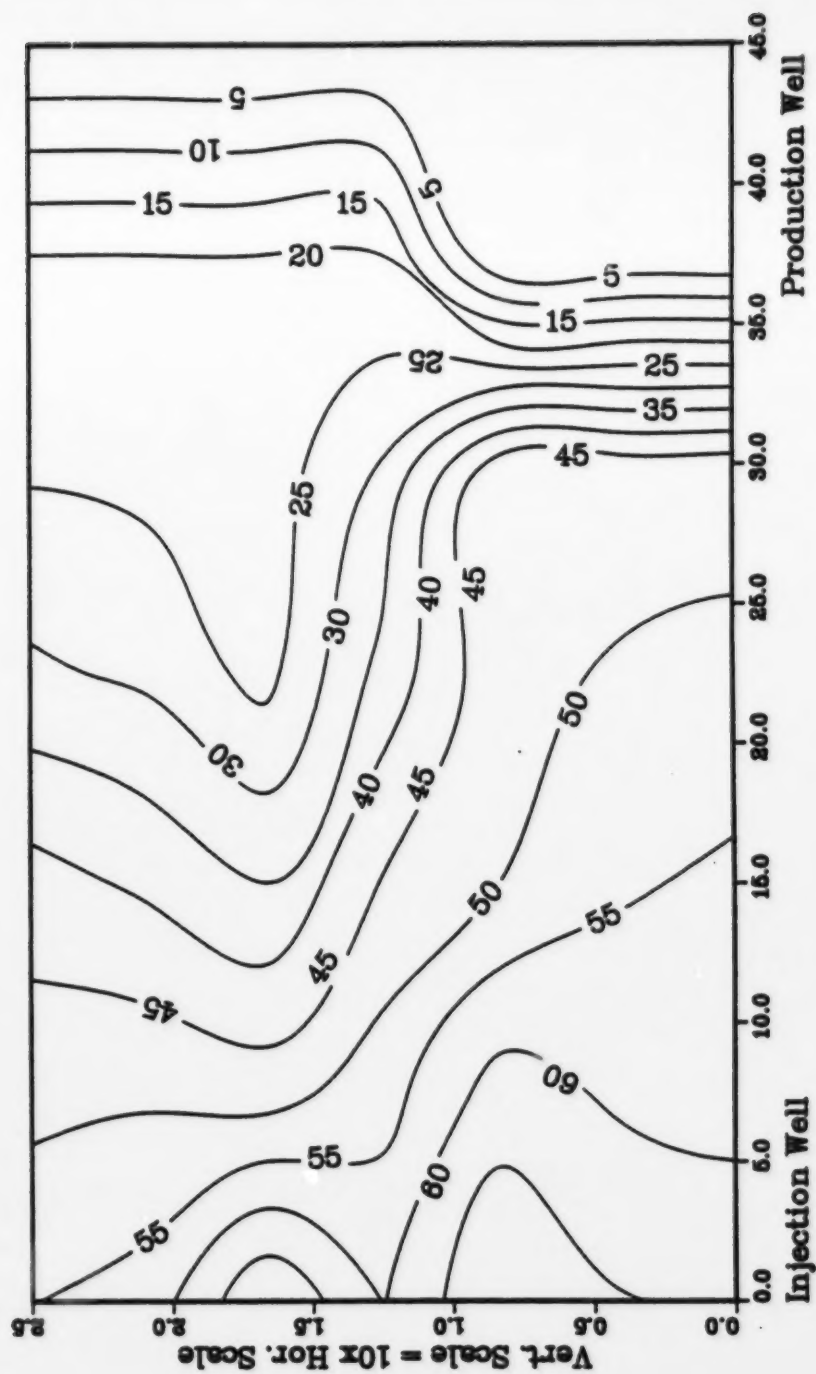


**Figure A.226 :Run 59 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

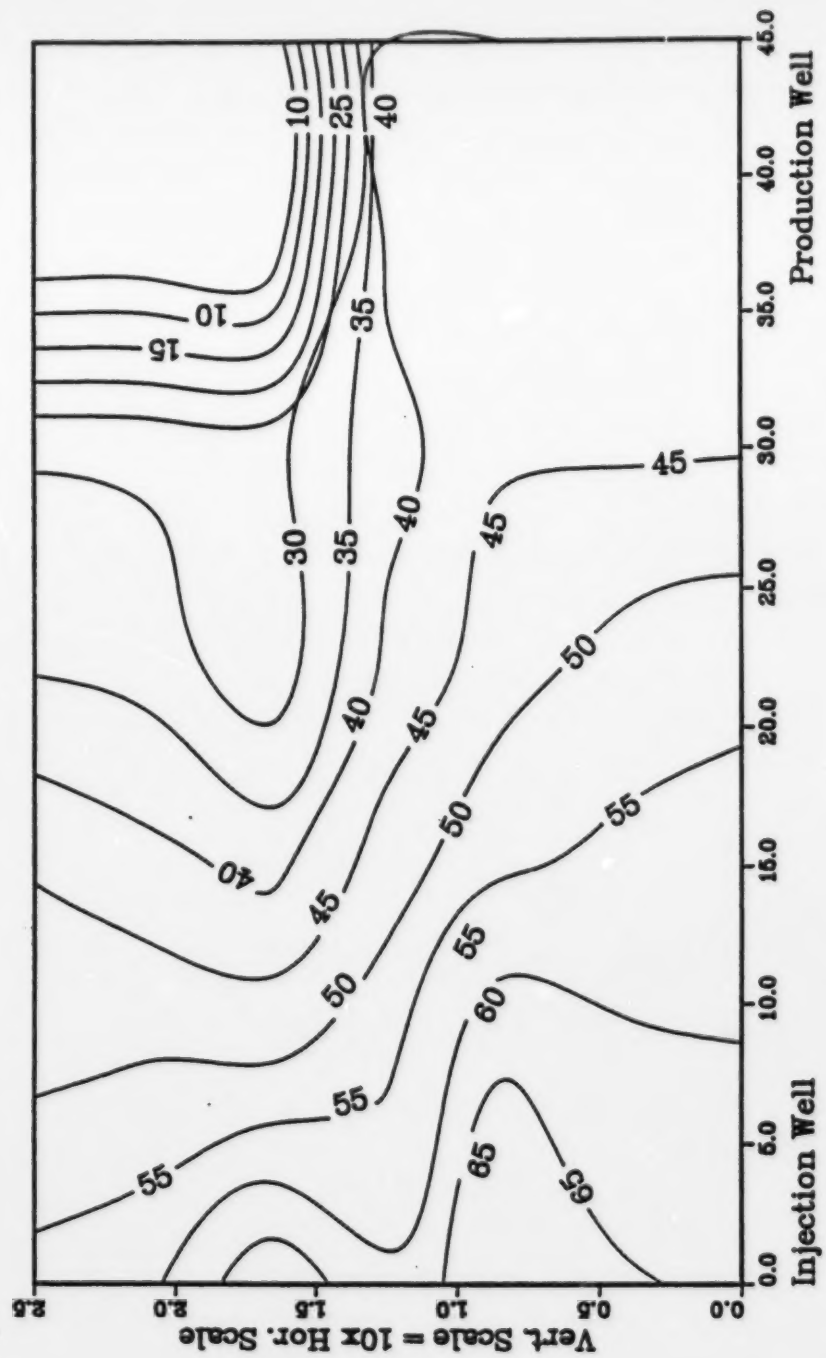
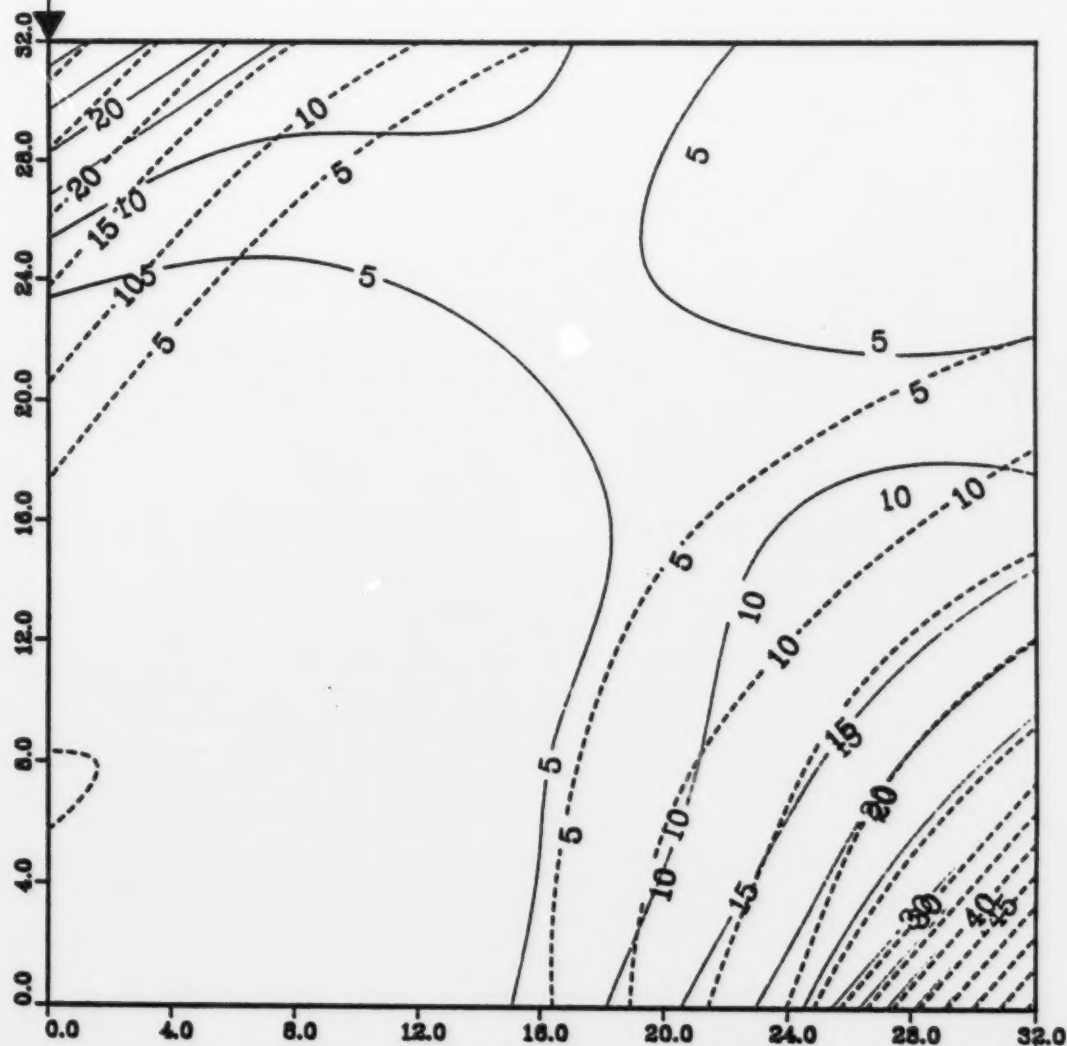


Figure A.227 : Run 62
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.228 : Run 62
 Gas Inj. Solv.—Steamflood in B.W. Model

Temperature Profile for
 0.50 Pore Volumes Injected

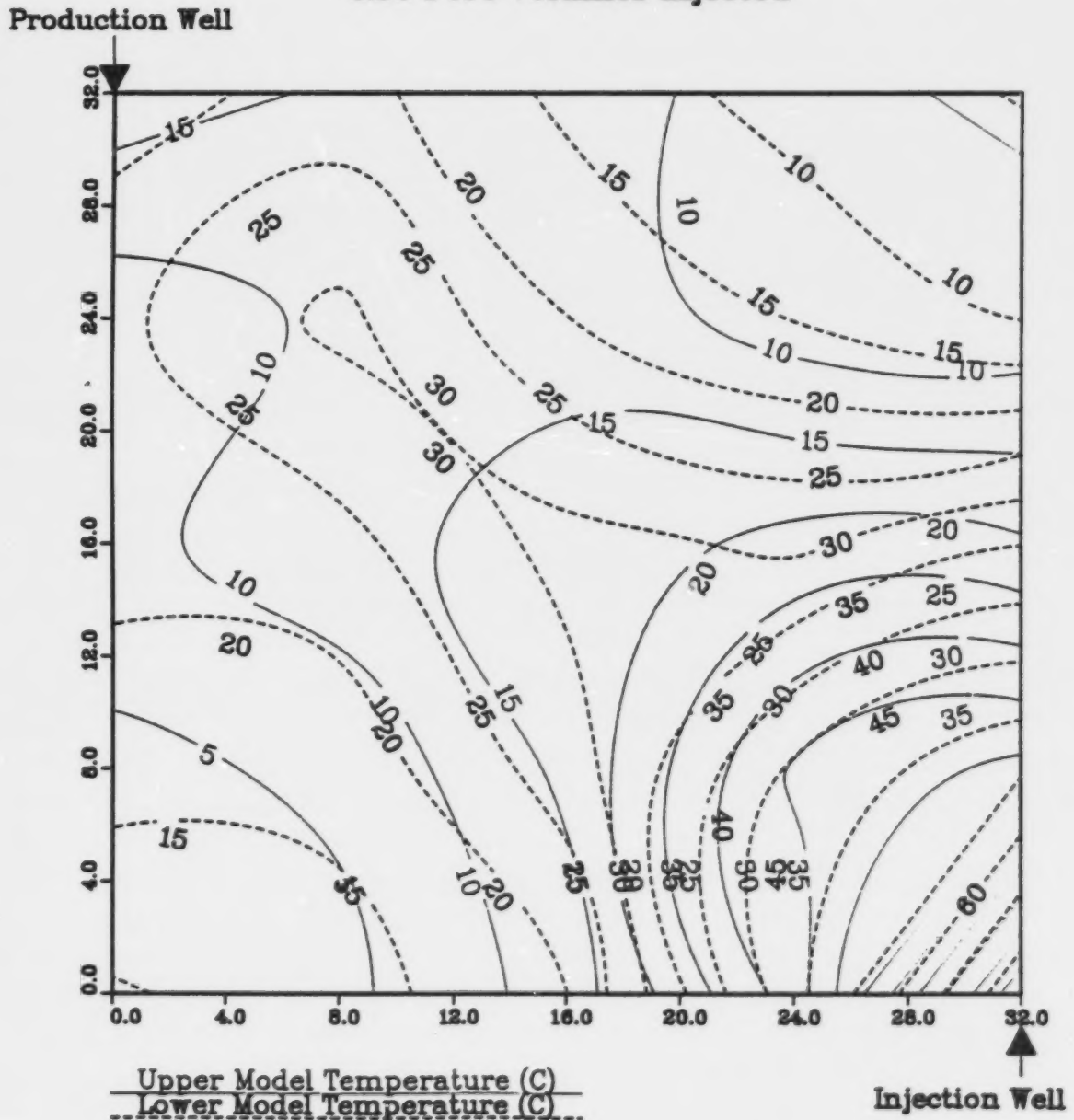
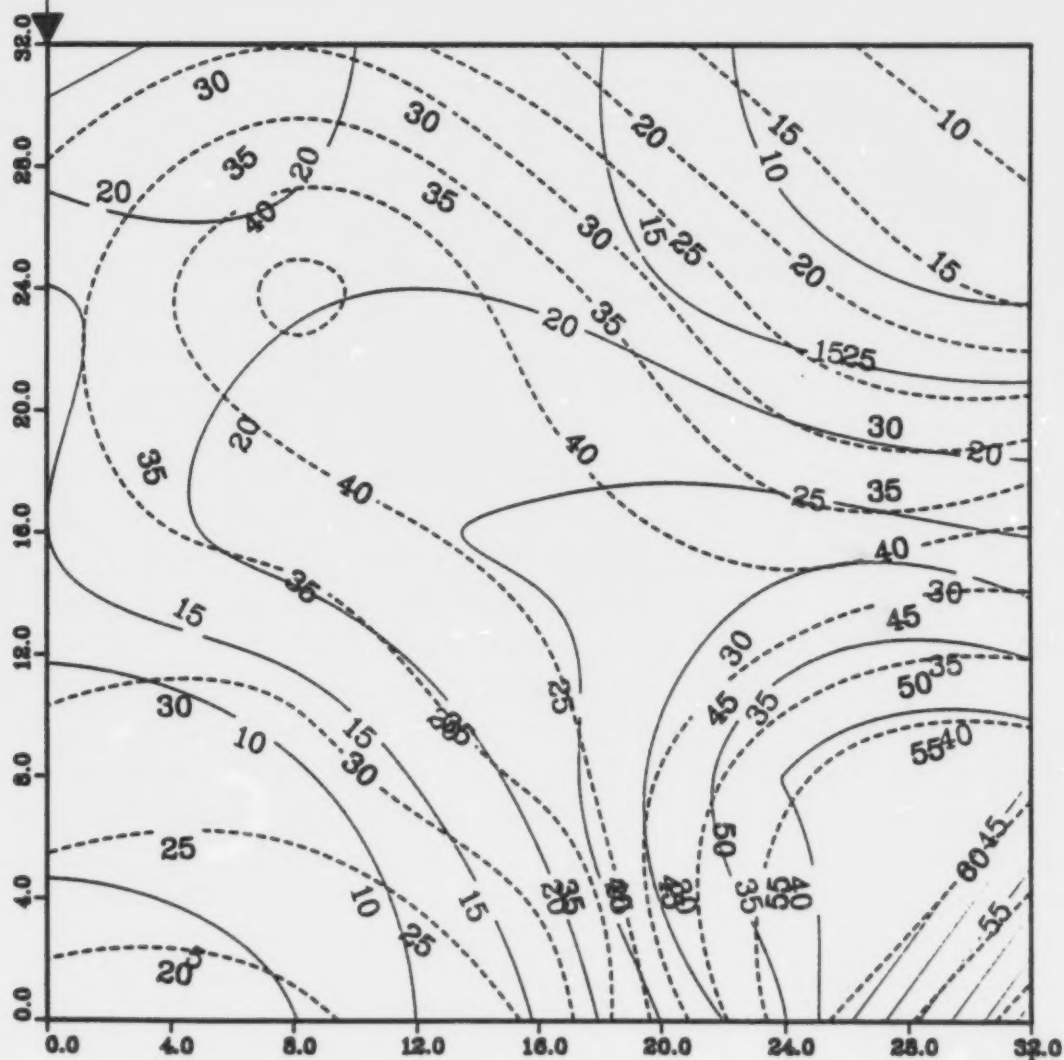


Figure A.229 : Run 62
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

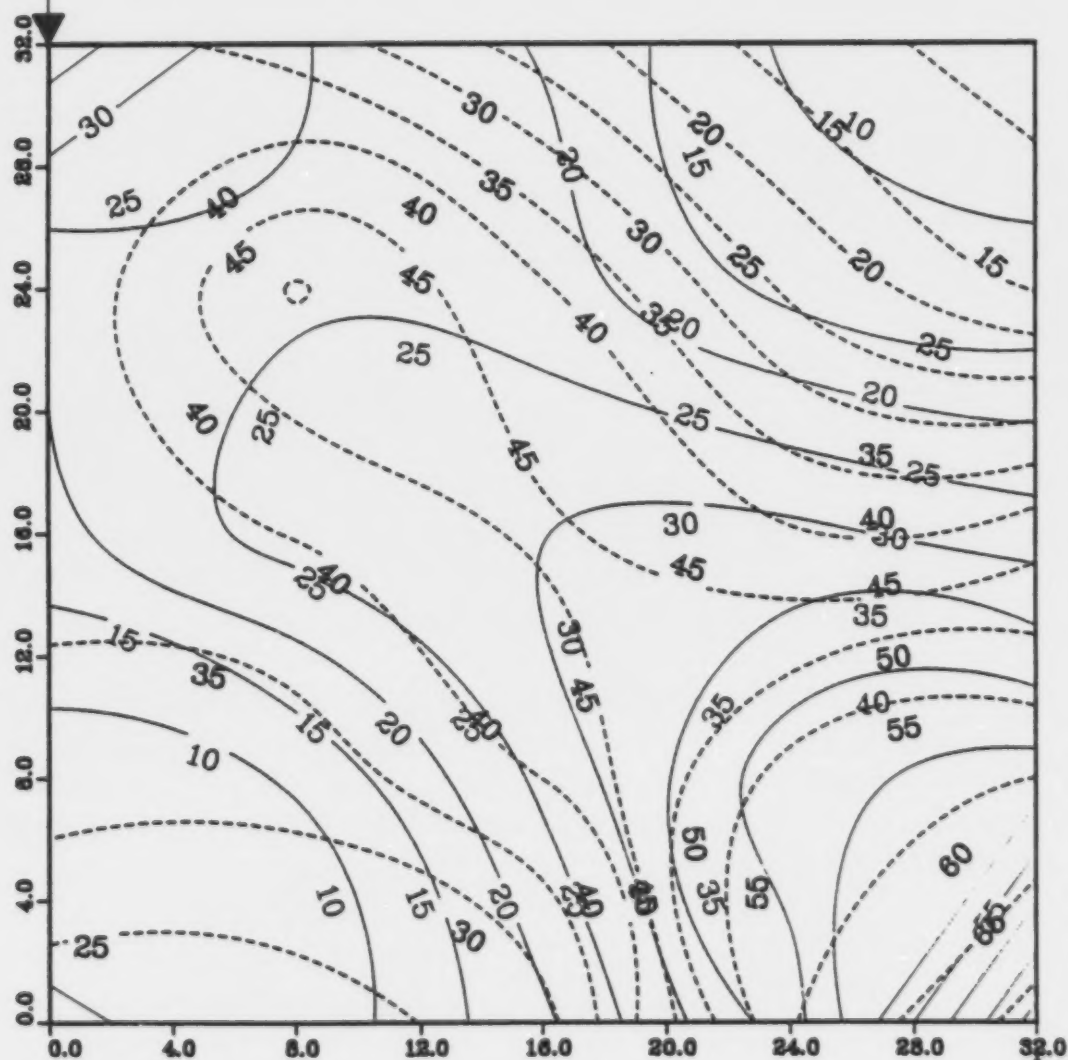
Lower Model Temperature (C)

Injection Well

Figure A.230 : Run 62
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

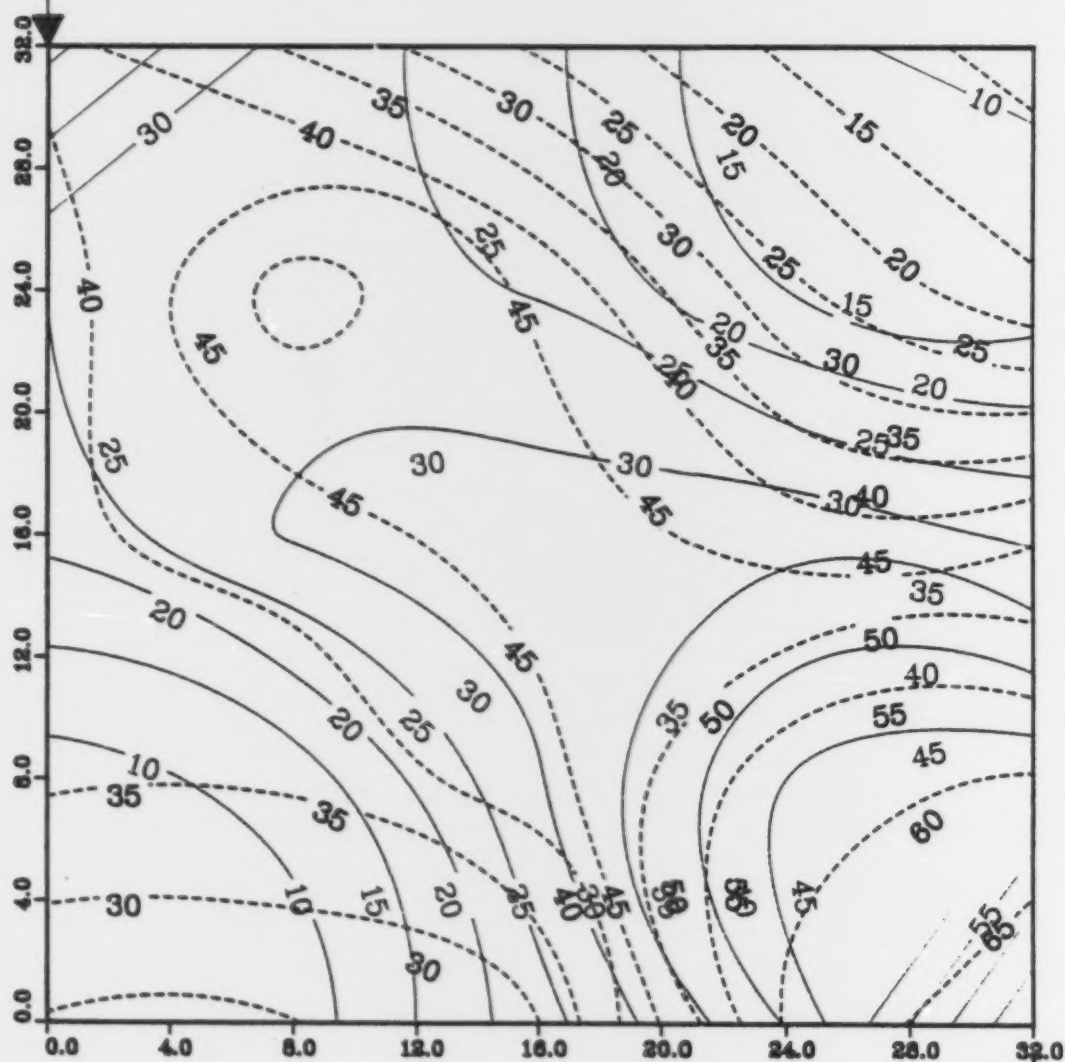
Lower Model Temperature (C)

Injection Well

Figure A.231 : Run 62
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 1.25 Pore Volumes Injected

Production Well



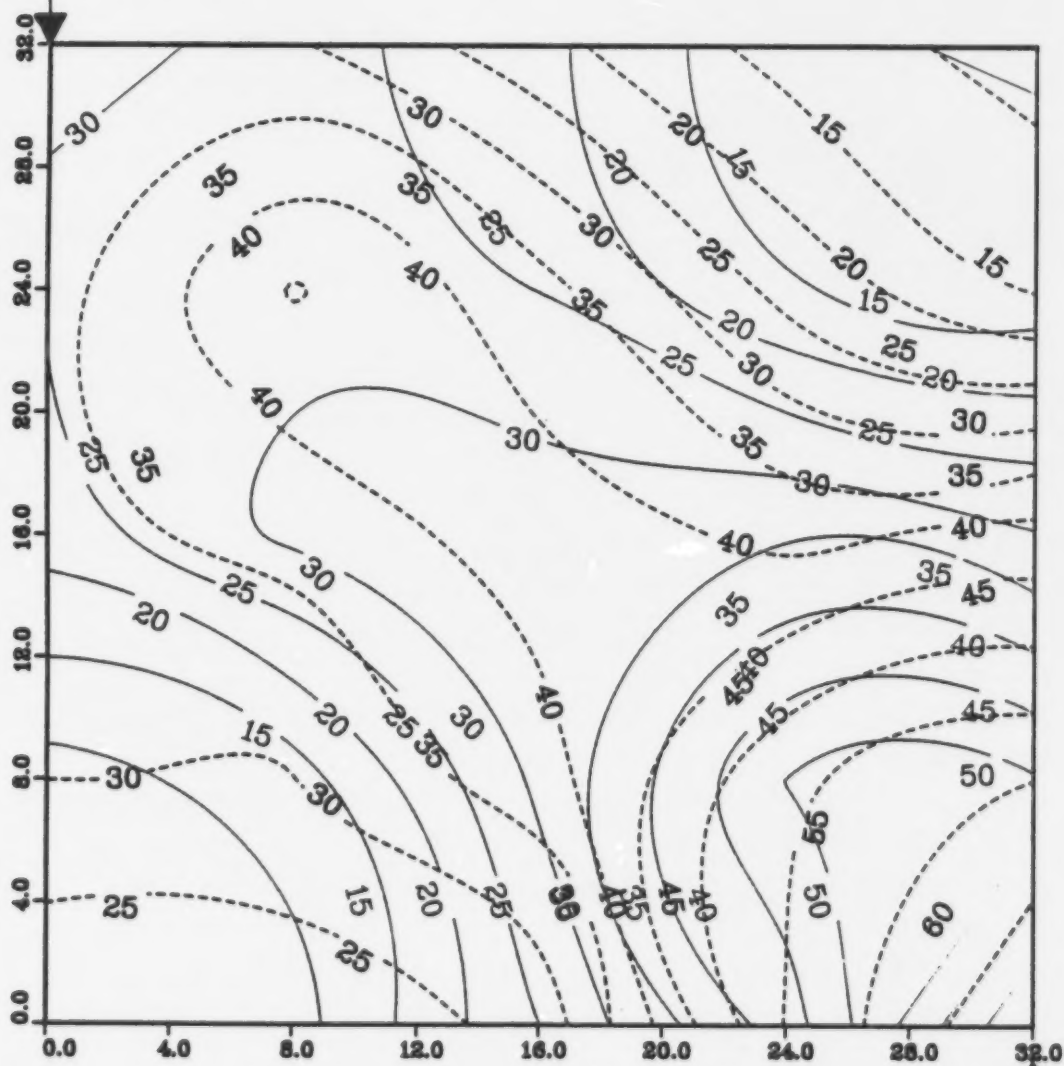
Upper Model Temperature (C)
 Lower Model Temperature (C)

Injection Well

Figure A.232 : Run 62
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

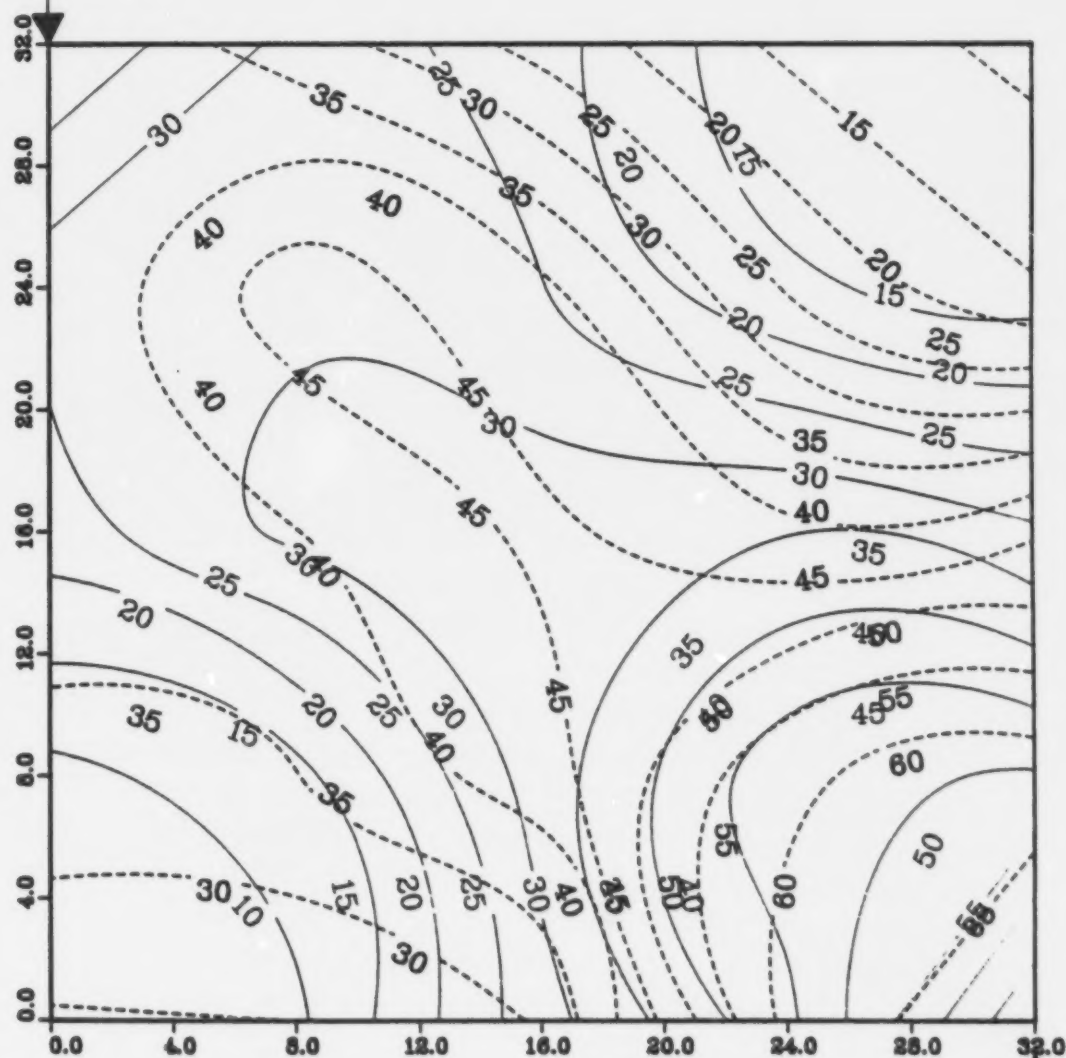
Lower Model Temperature (C)

Injection Well

Figure A.233 : Run 62
Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.234 : Run 62
 Gas Inj. Solv.-Steamflood in B.W. Model

Temperature Profile for
 2.00 Pore Volumes Injected

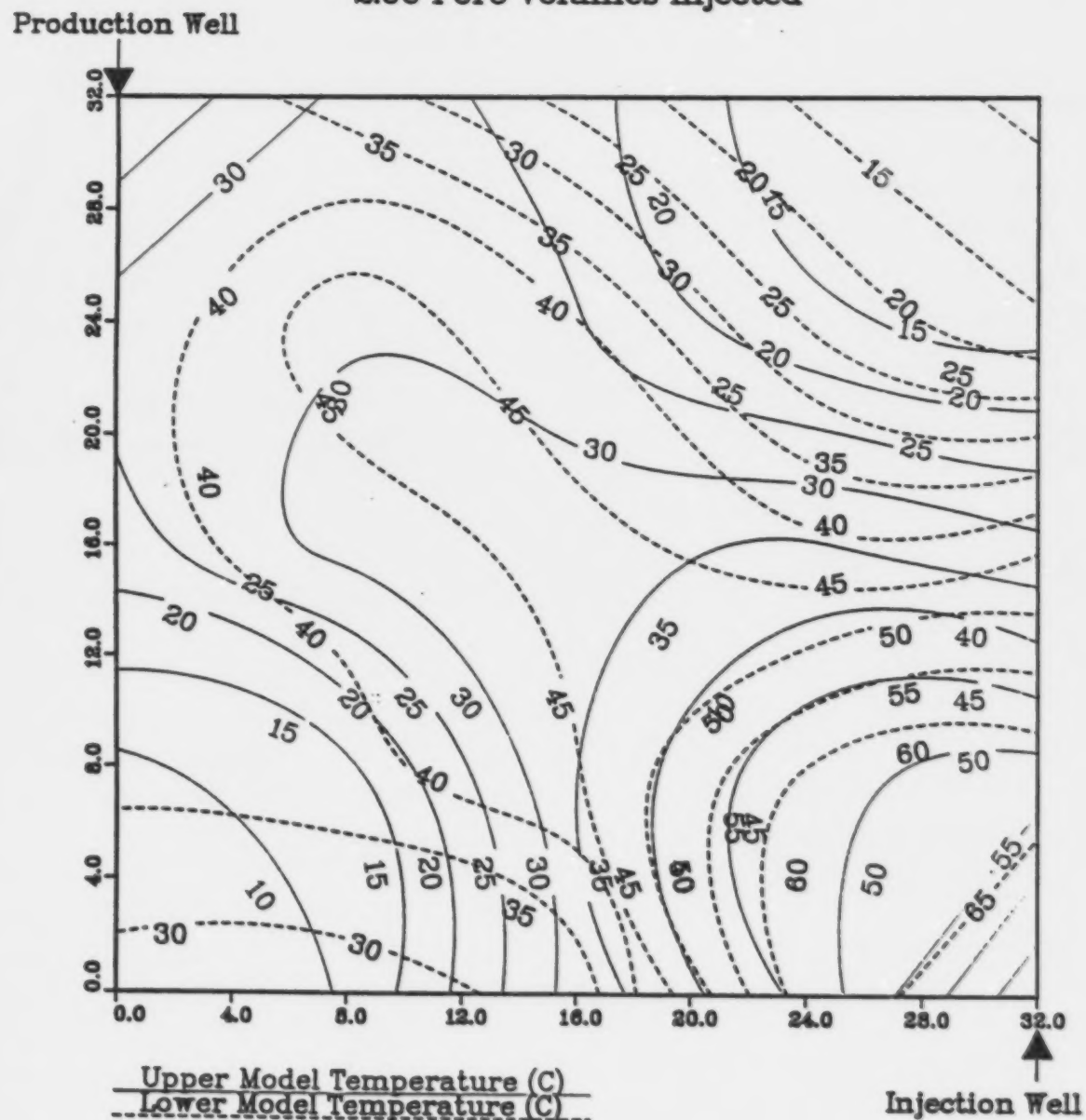


**Figure A.235 :Run 62 Temp Profile
Injector to Producer Cross-Section
0.25 Pore Volumes Injected.**

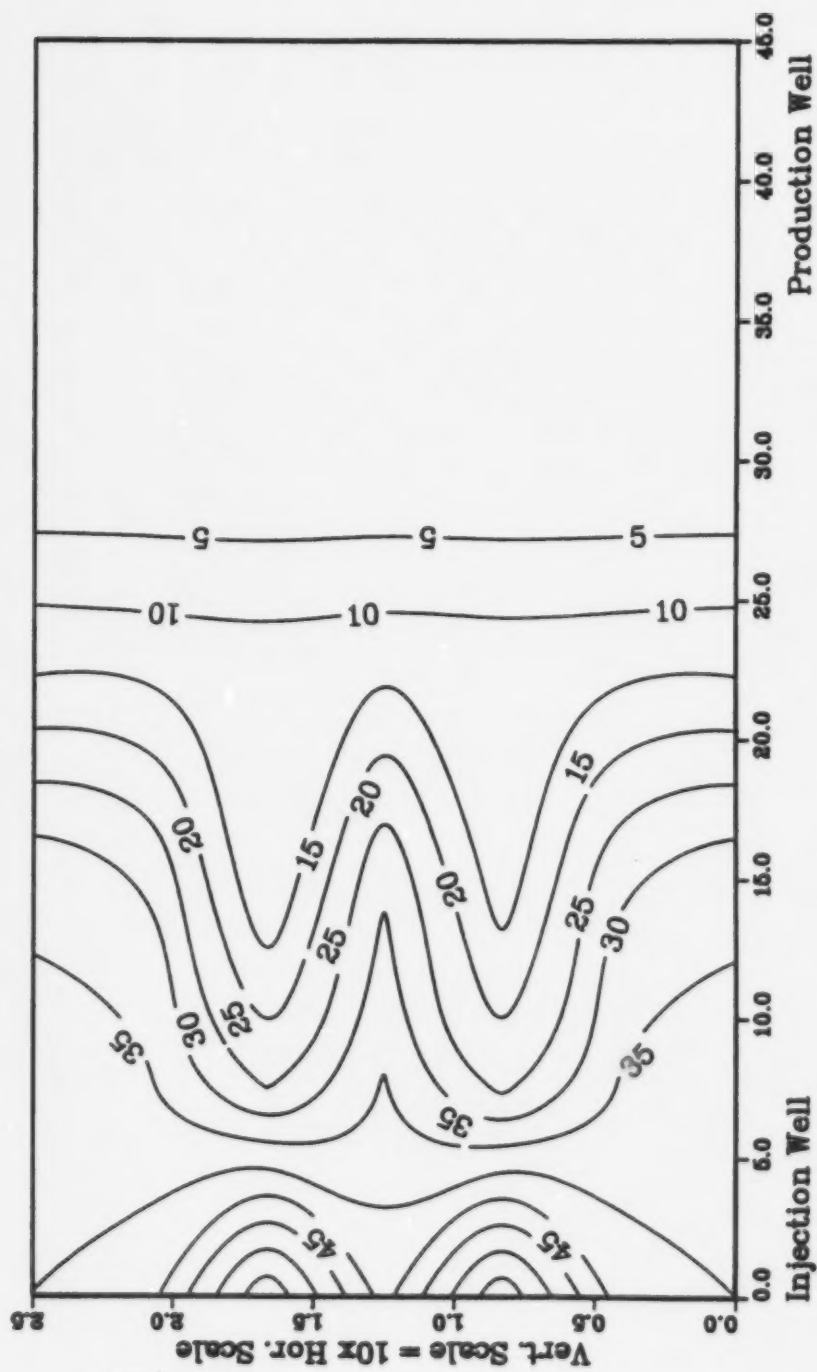


**Figure A.236 :Run 62 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

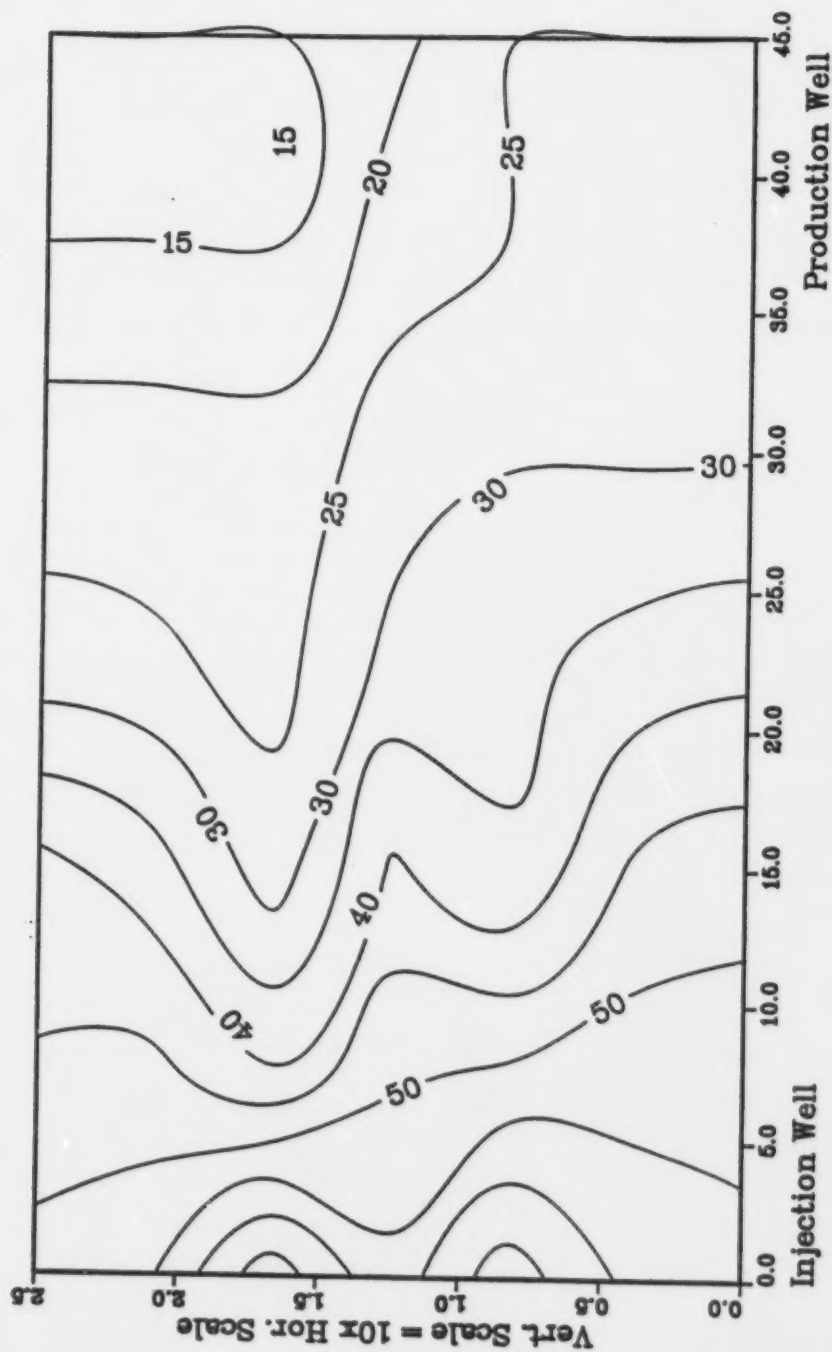


**Figure A.237 :Run 62 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

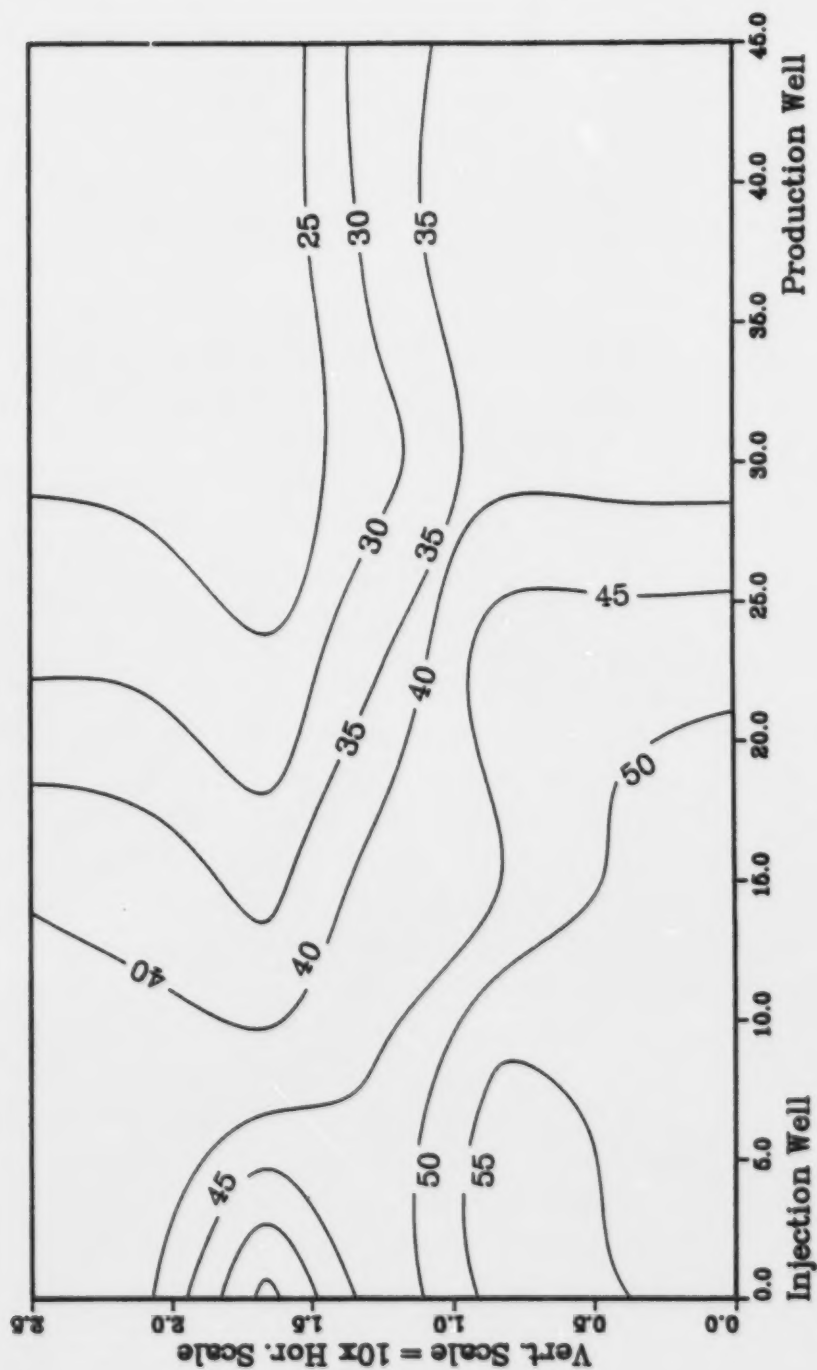


**Figure A.238 :Run 62 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

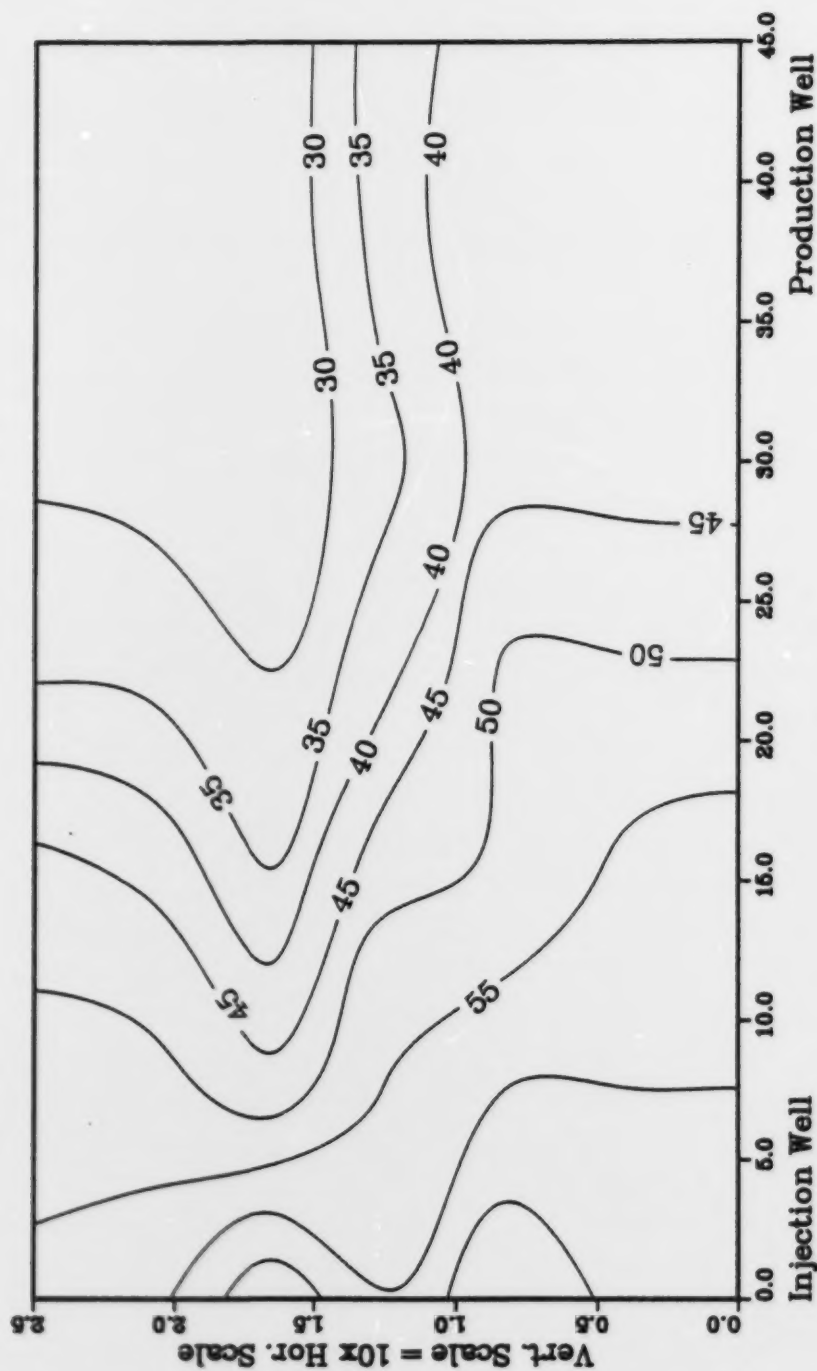
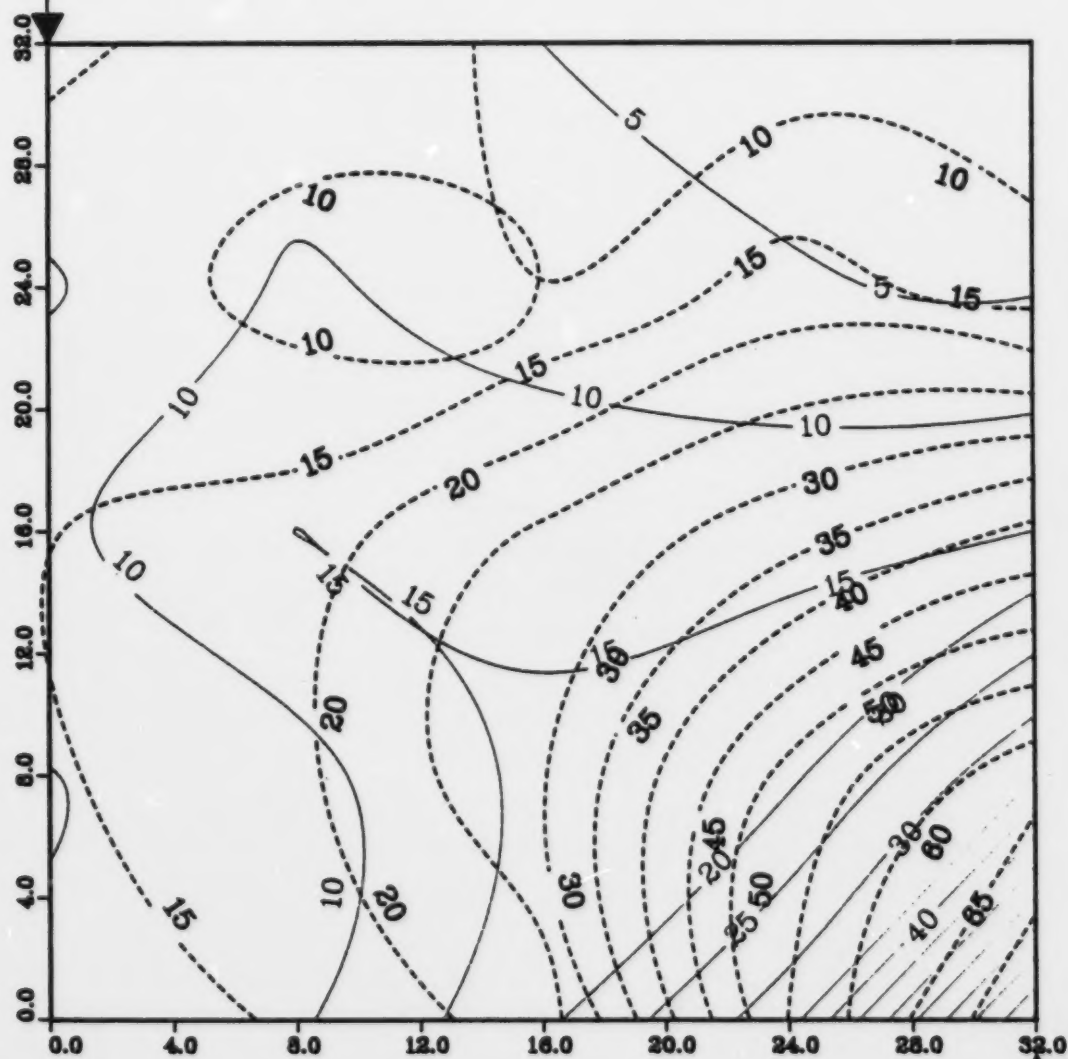


Figure A.239 : Run 63
Steamflood With Partial B.W. Barrier

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

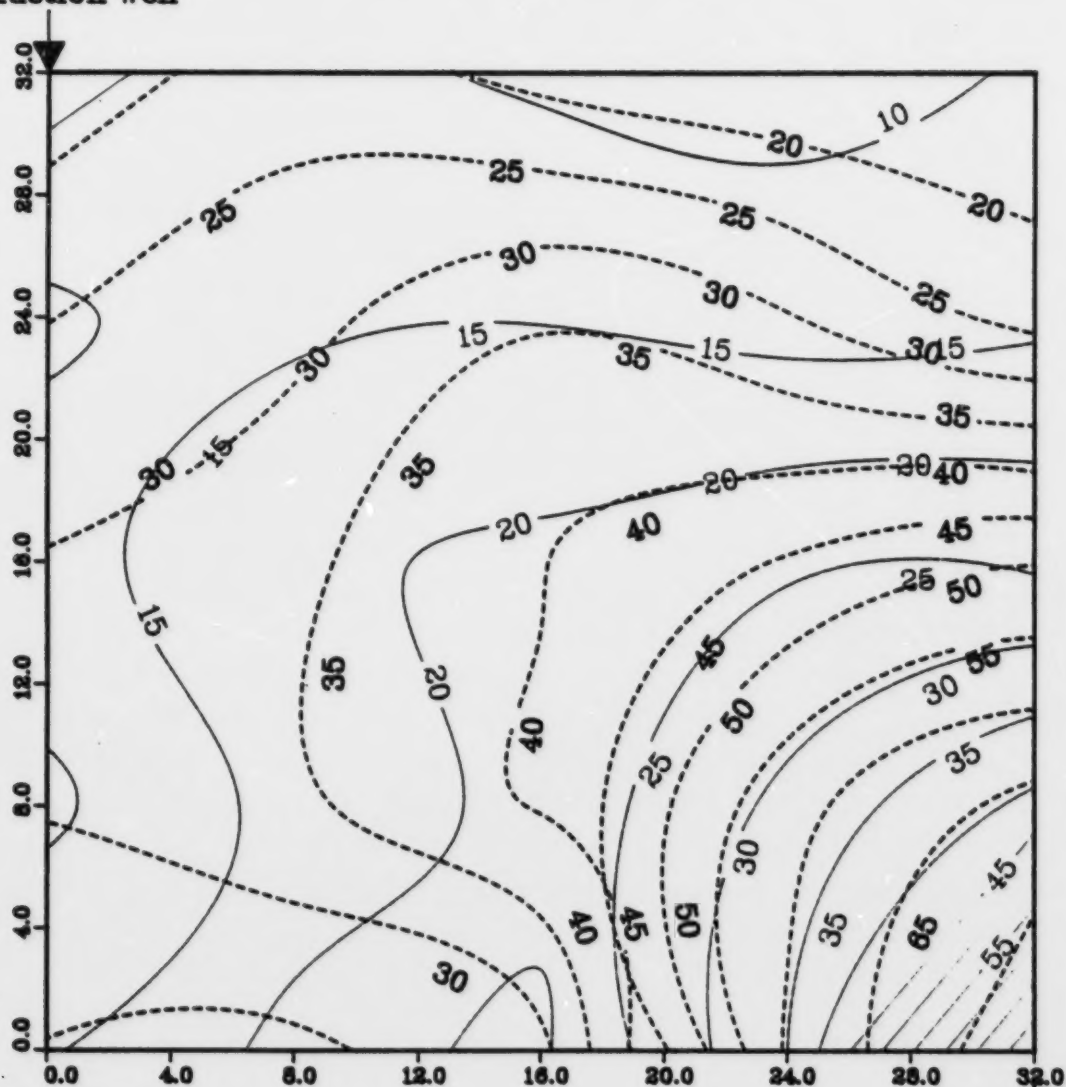
Lower Model Temperature (C)

Injection Well

Figure A240 : Run 63
Steamflood With Partial B.W. Barrier

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

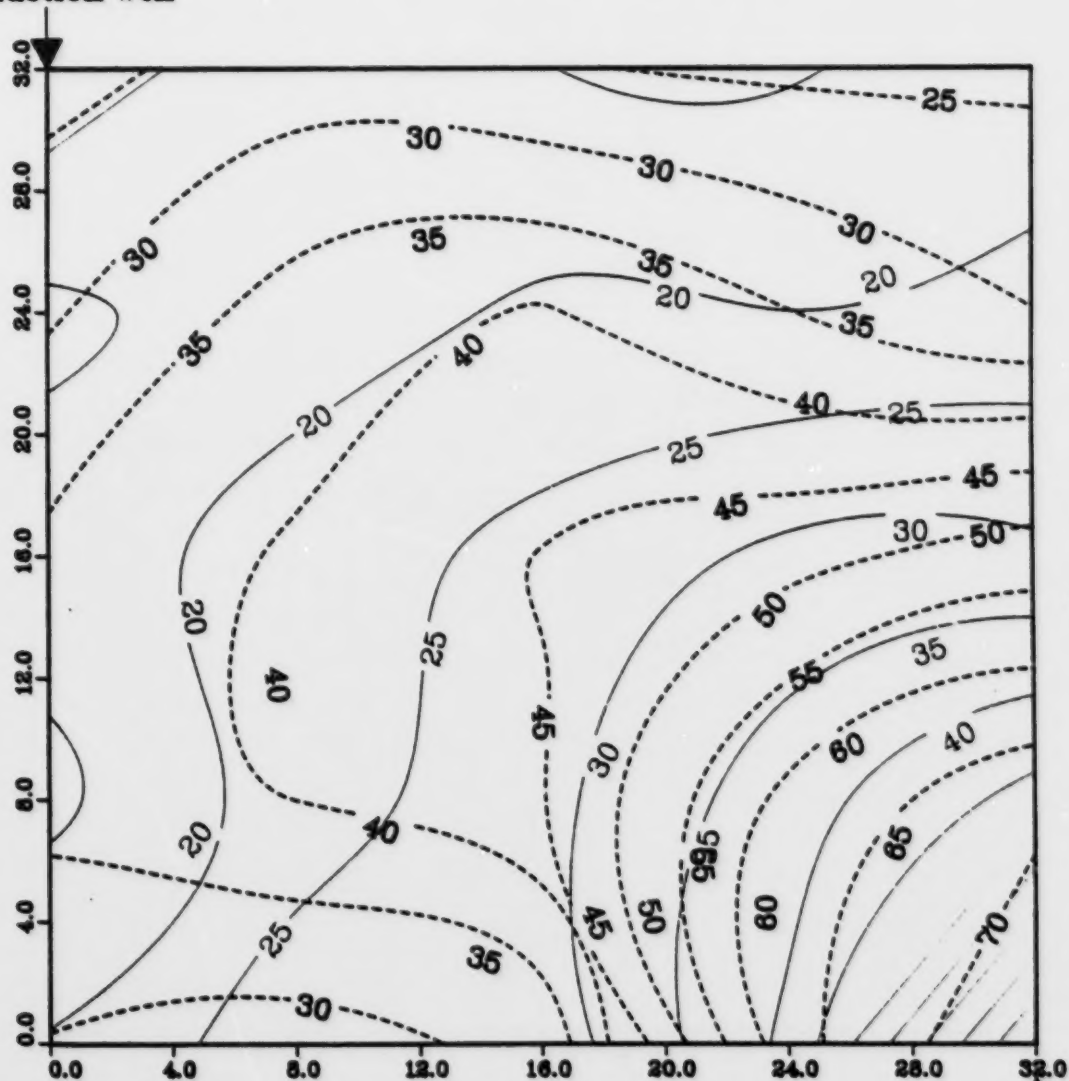
Lower Model Temperature (C)

Injection Well

Figure A.241 : Run 63
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

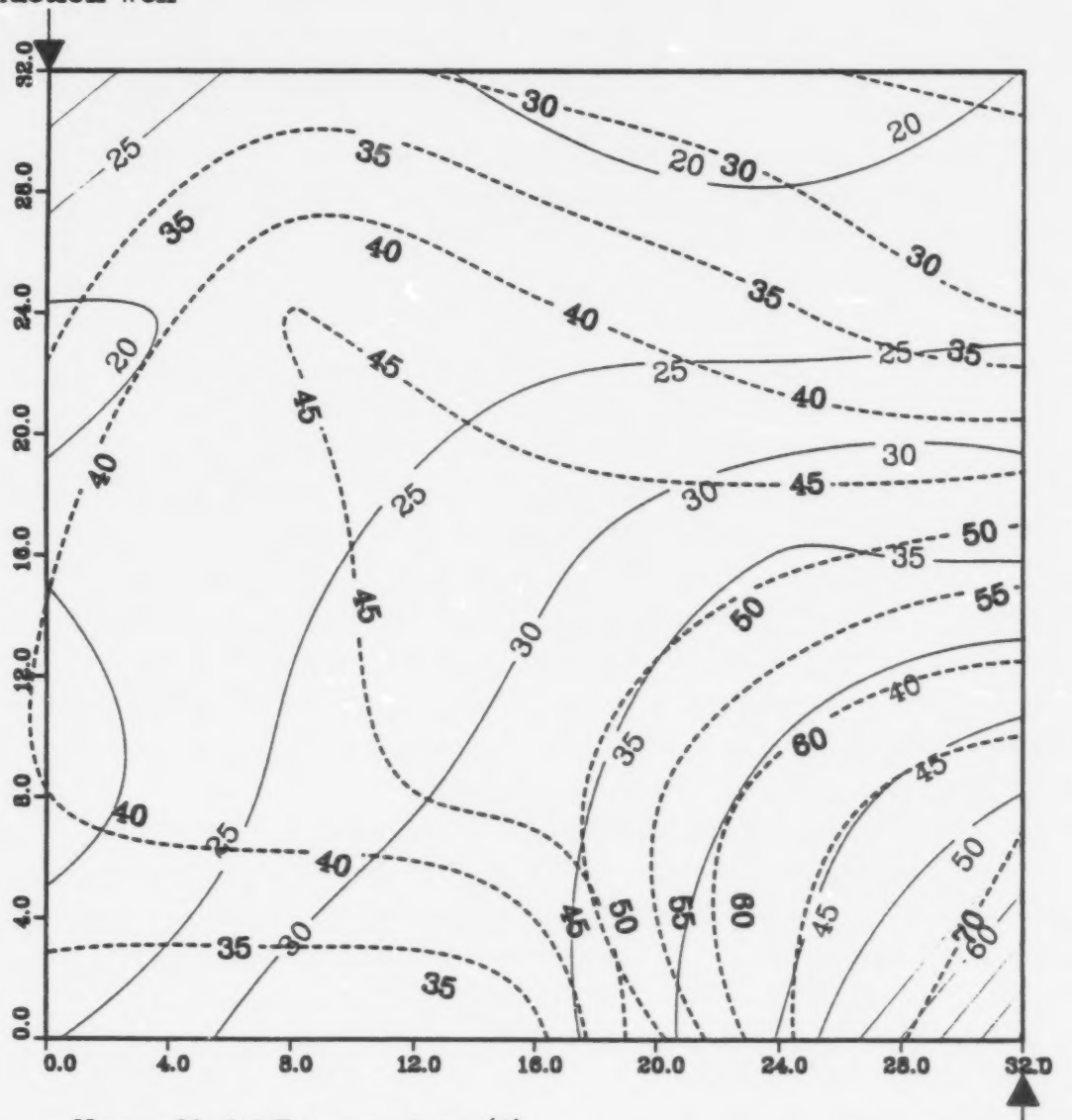
Lower Model Temperature (C)

Injection Well

Figure A.242 : Run 63
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.243 : Run 63
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.25 Pore Volumes Injected

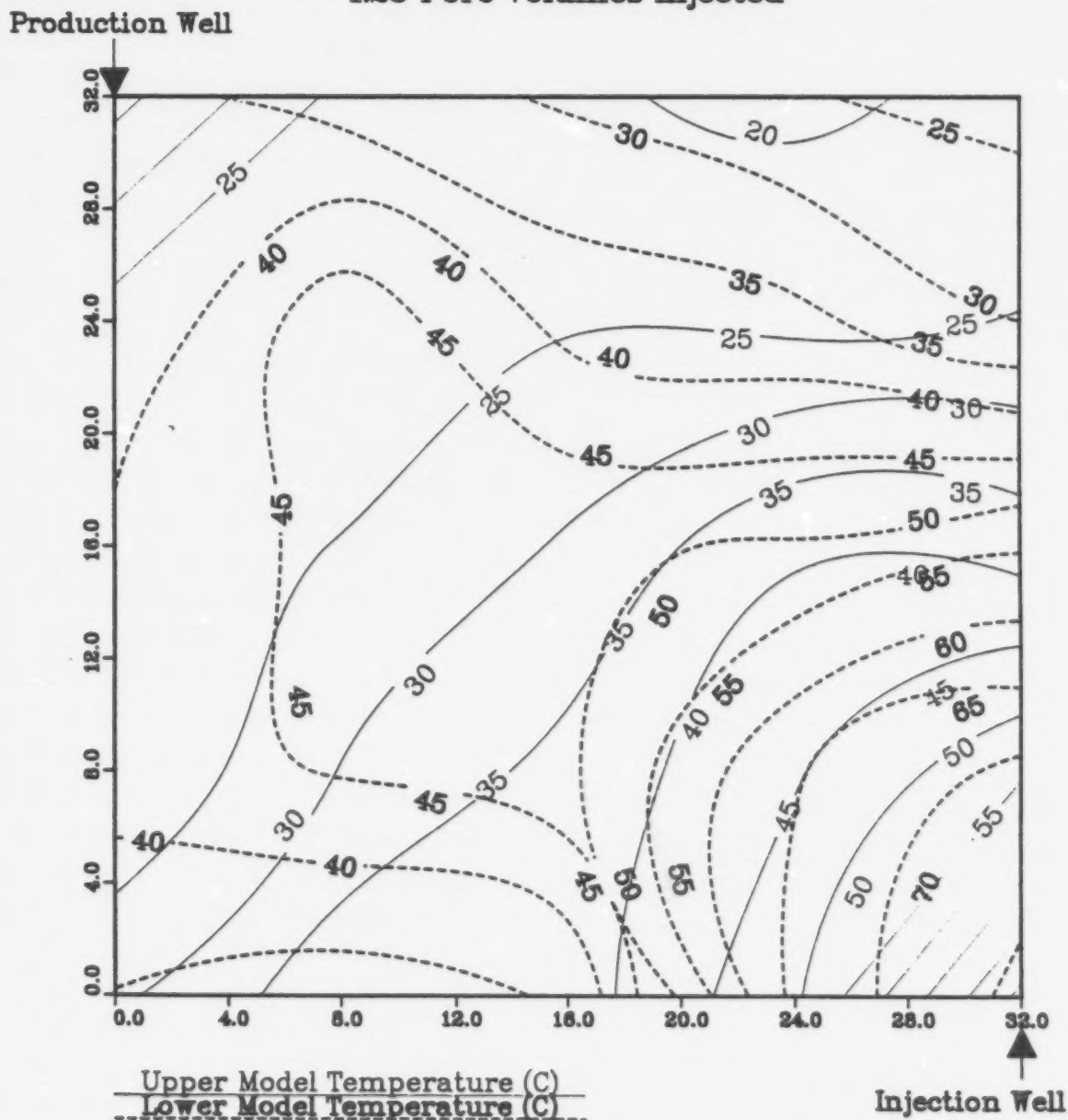
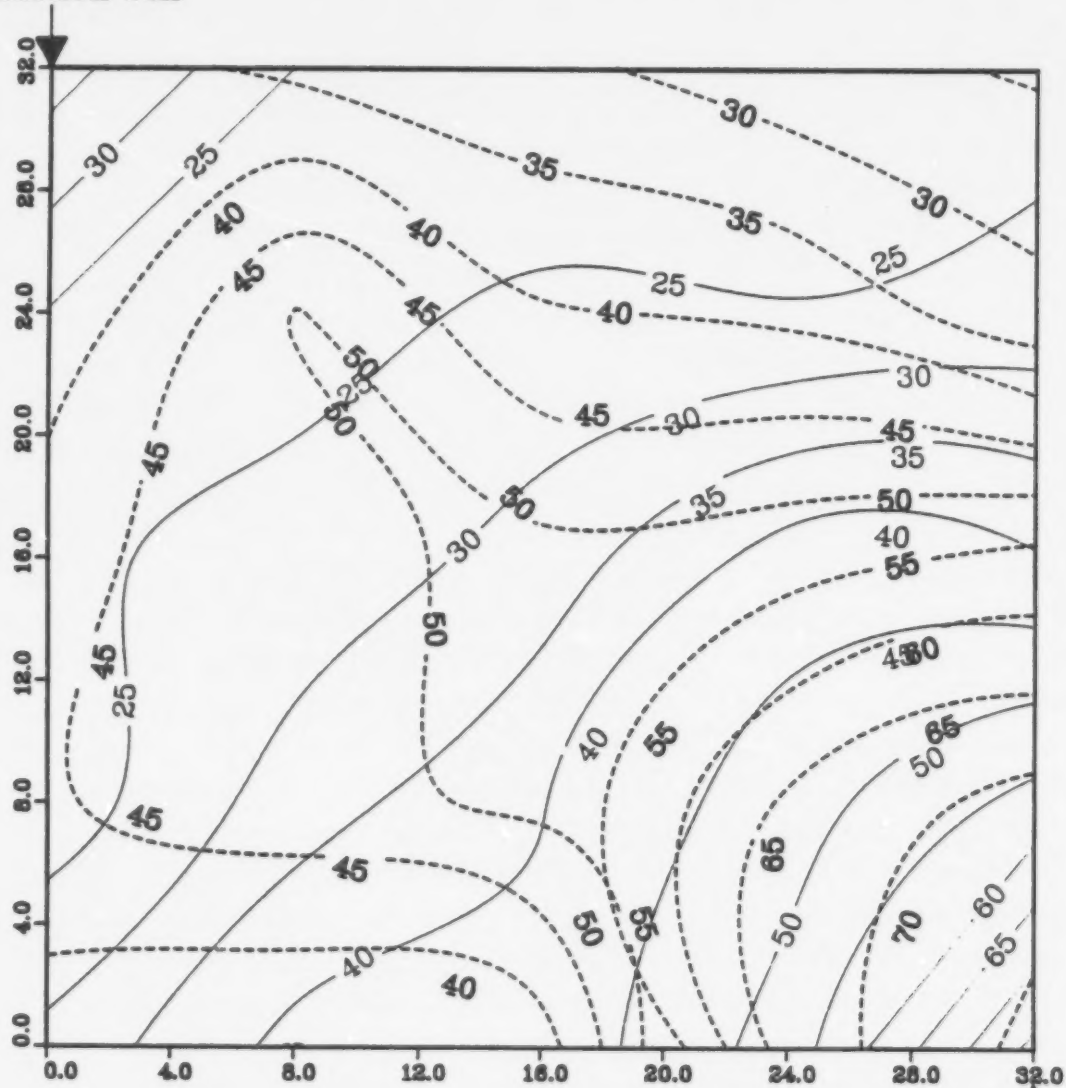


Figure A.244 : Run 63

Steamflood With Partial B.W. Barrier

Temperature Profile for
1.50 Pore Volumes Injected

Production Well

Upper Model Temperature (C)Lower Model Temperature (C)

Injection Well

Figure A.245 : Run 63
Steamflood With Partial B.W. Barrier

Temperature Profile for
1.75 Pore Volumes Injected

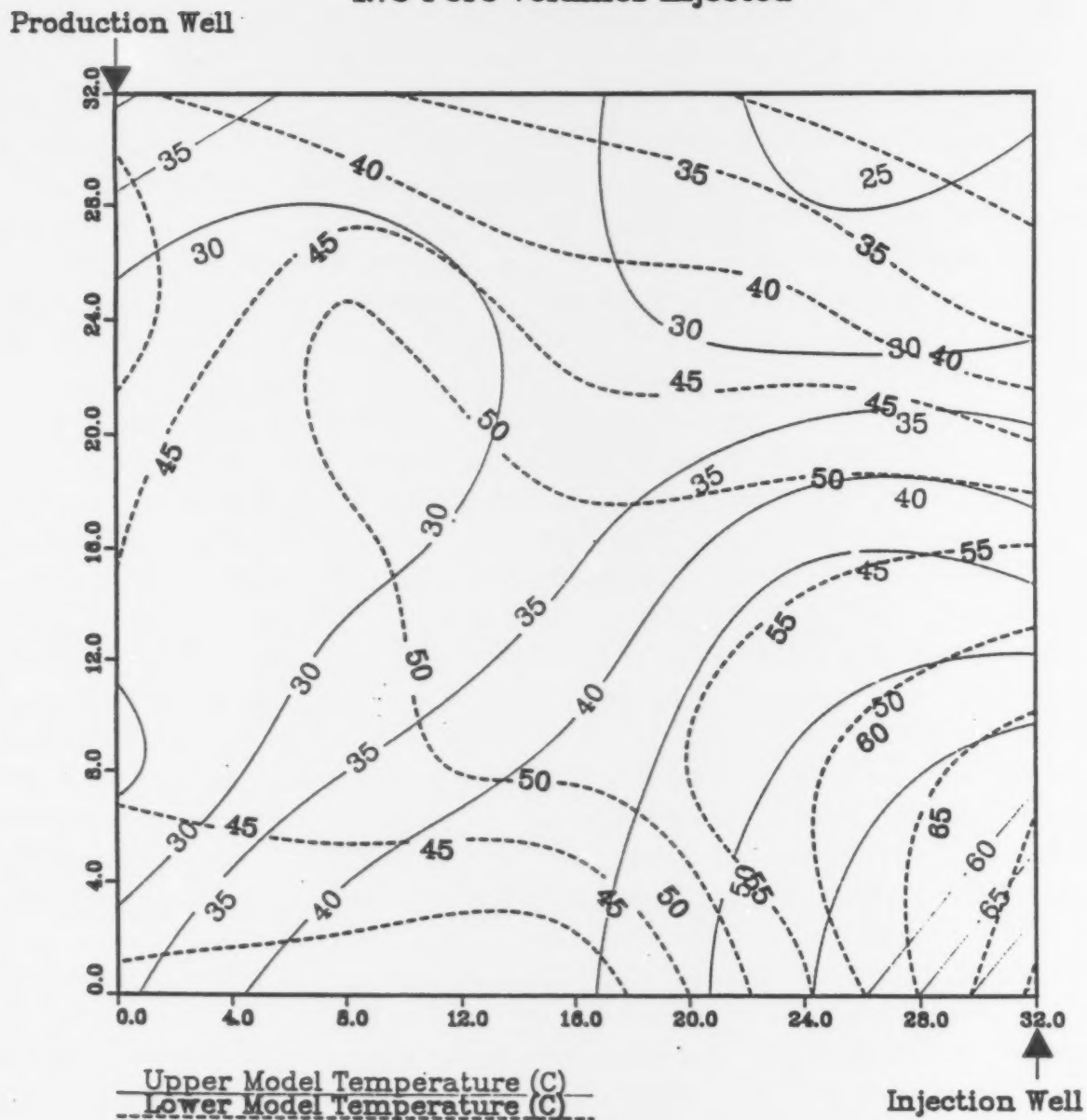
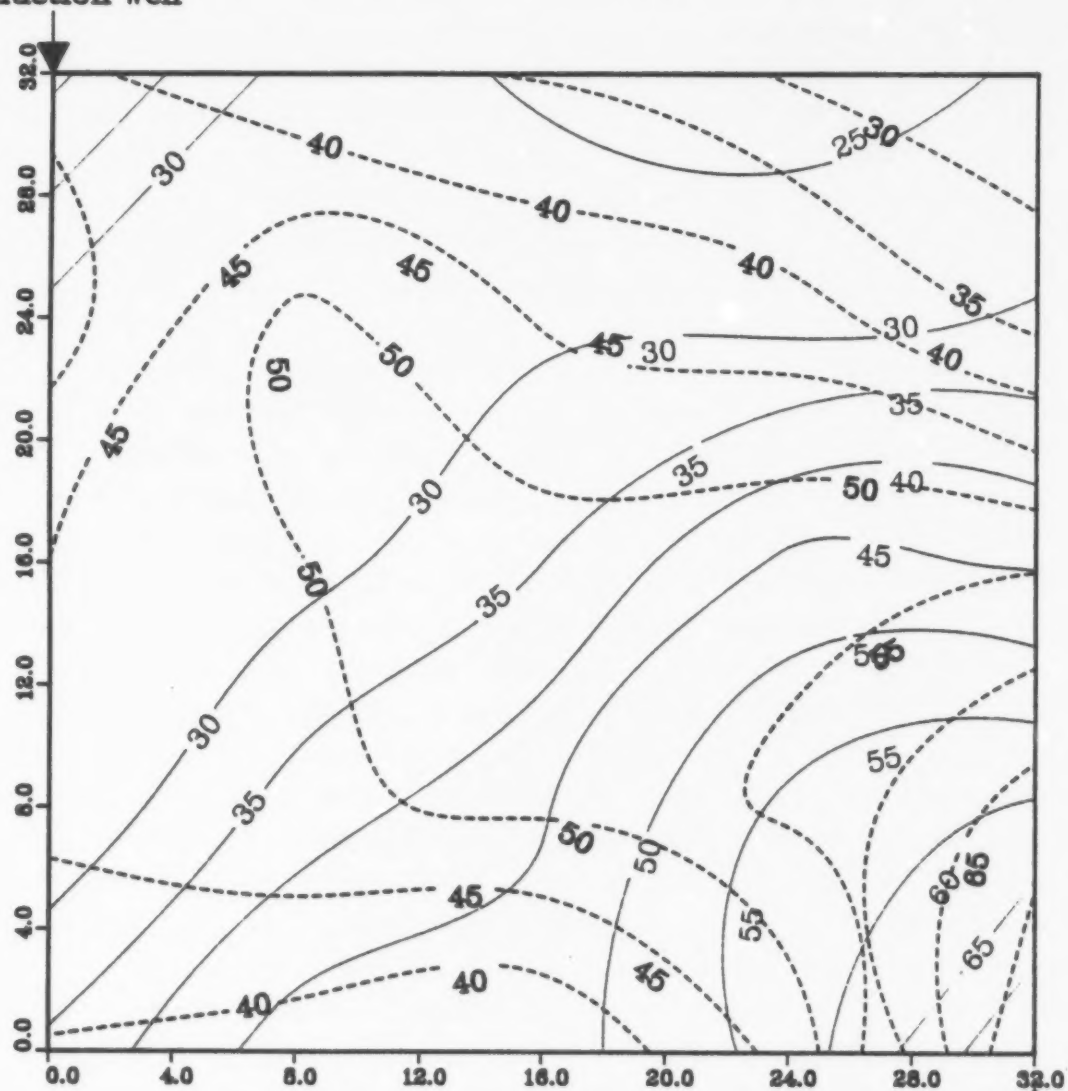


Figure A.246 : Run 63
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

**Figure A.247 :Run 63 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

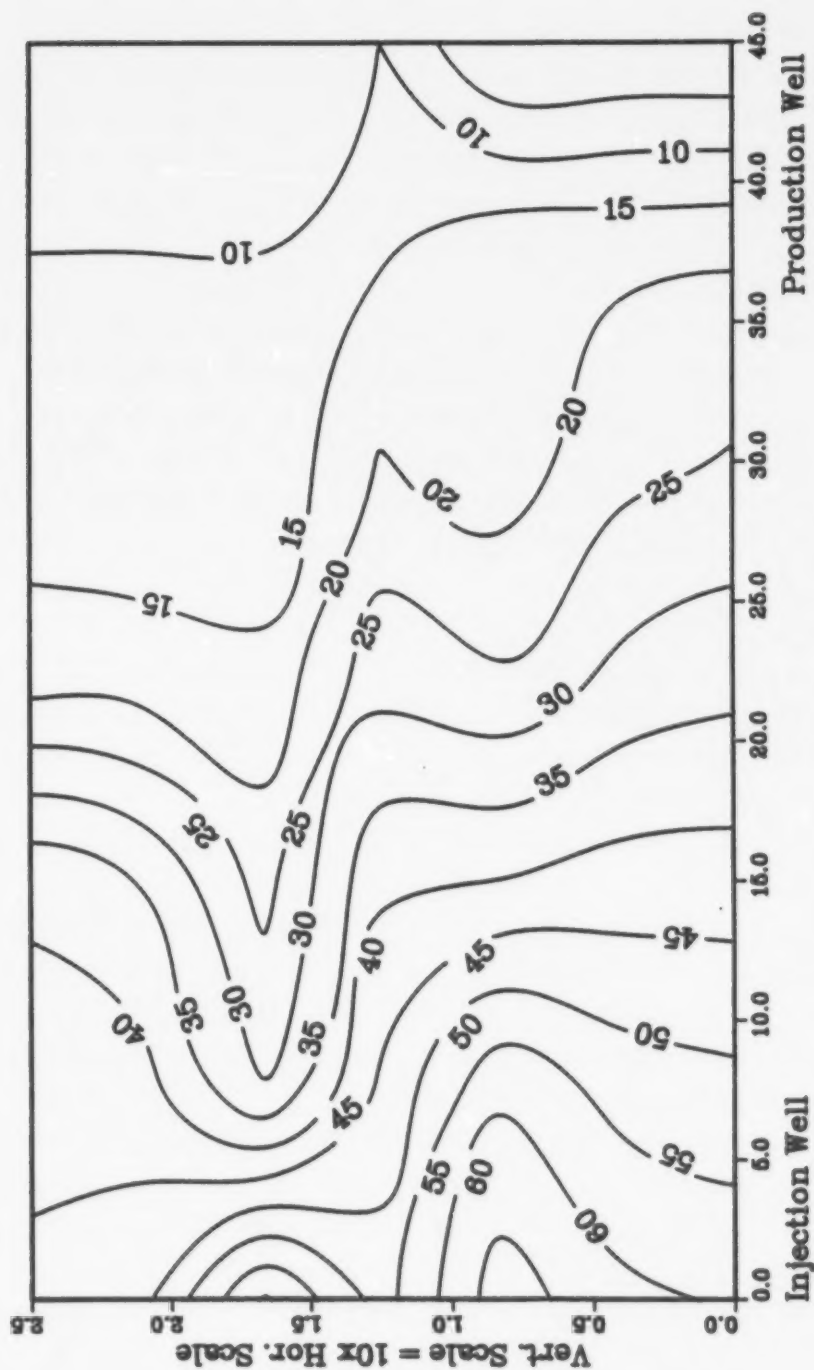


**Figure A.248 :Run 63 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

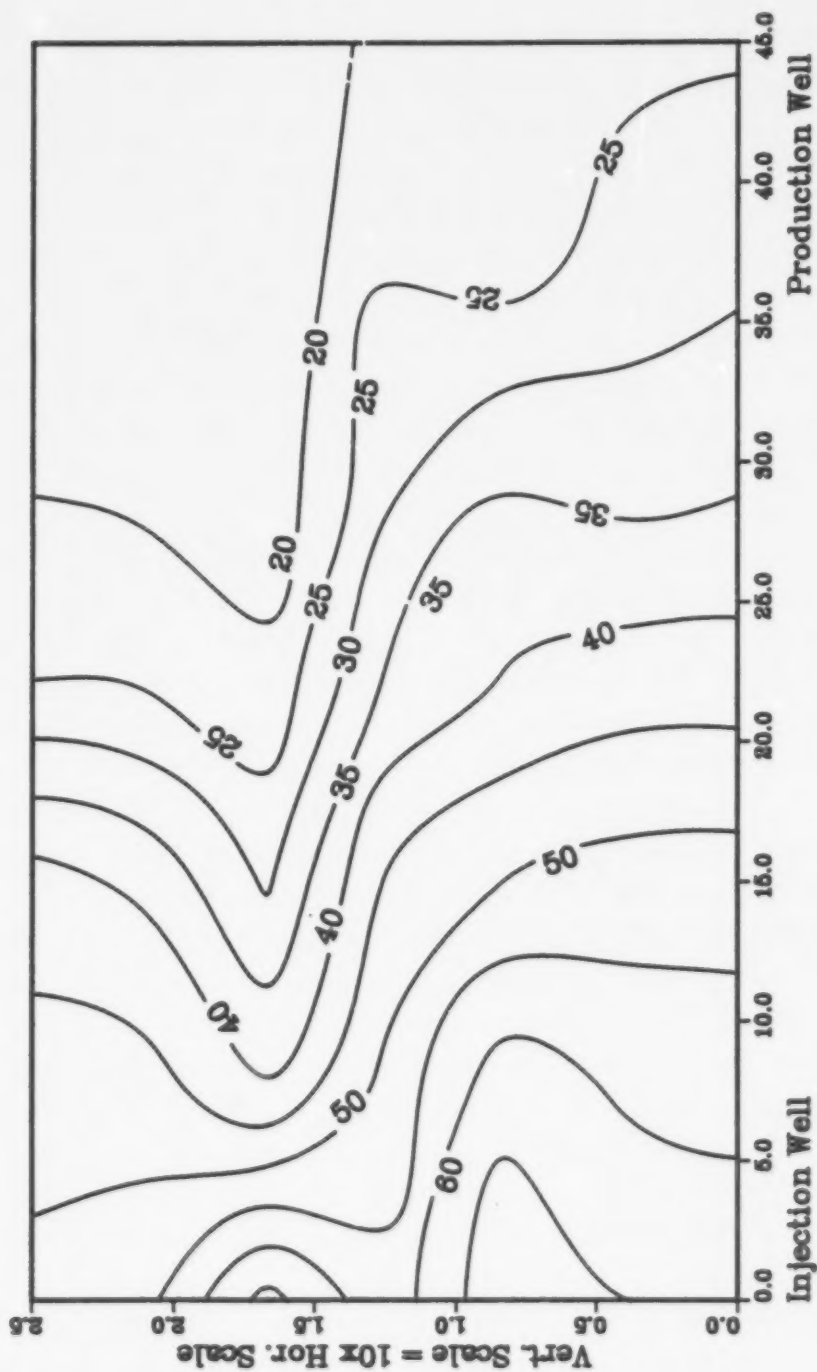


**Figure A.249 :Run 63 Temp Profile
Injector to Producer Cross-Section**
0.75 Pore Volumes Injected.

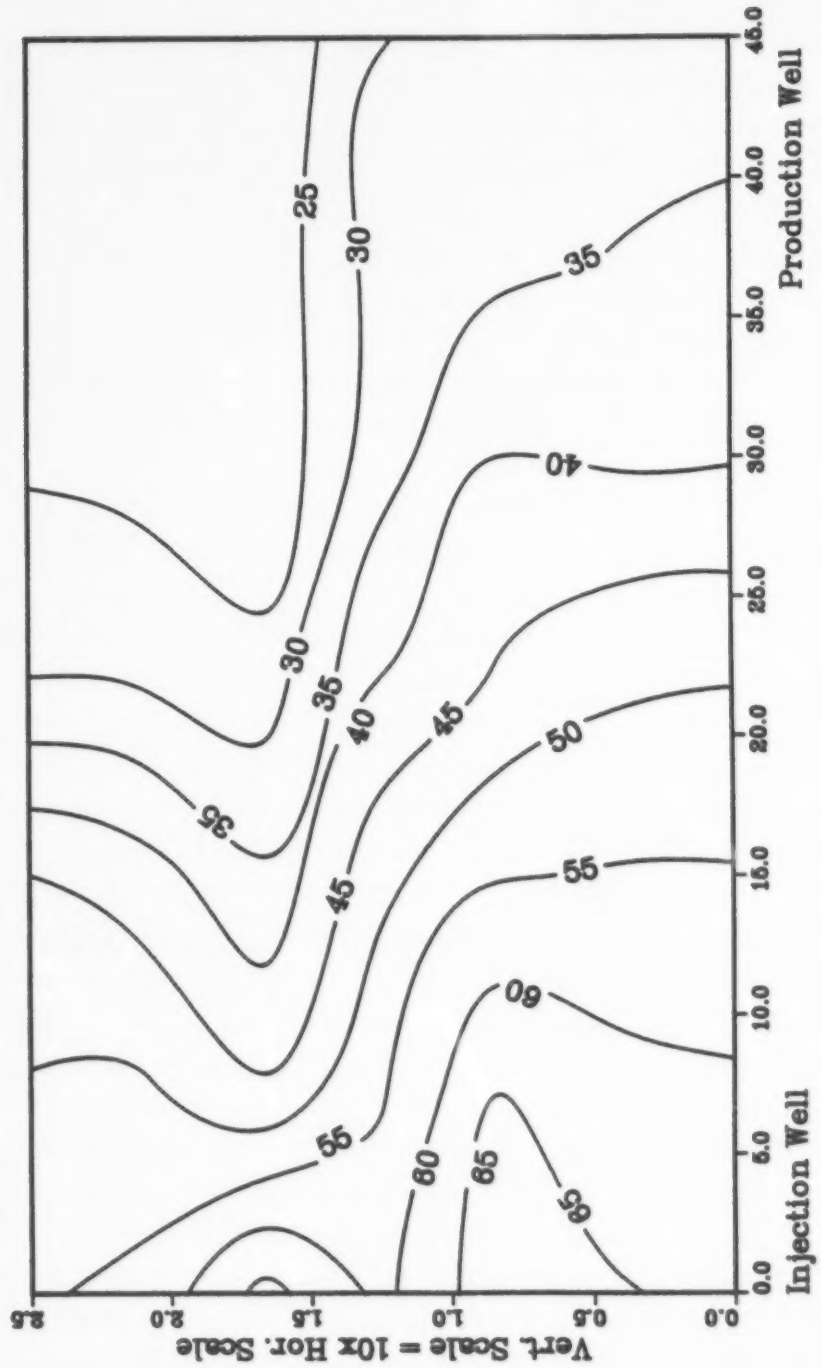


**Figure A.250 :Run 63 Temp Profile
Injector to Producer Cross-Section**
1.00 Pore Volumes Injected.

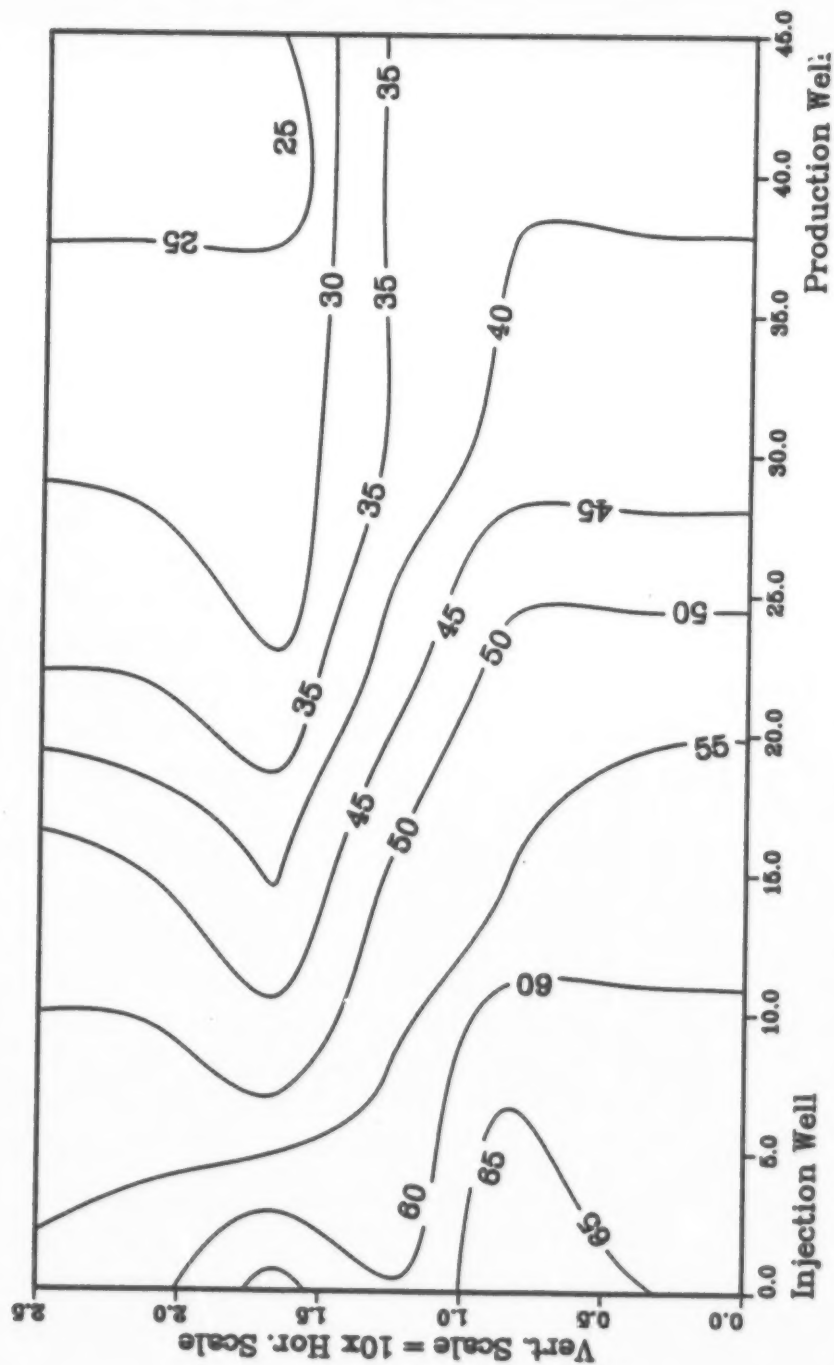
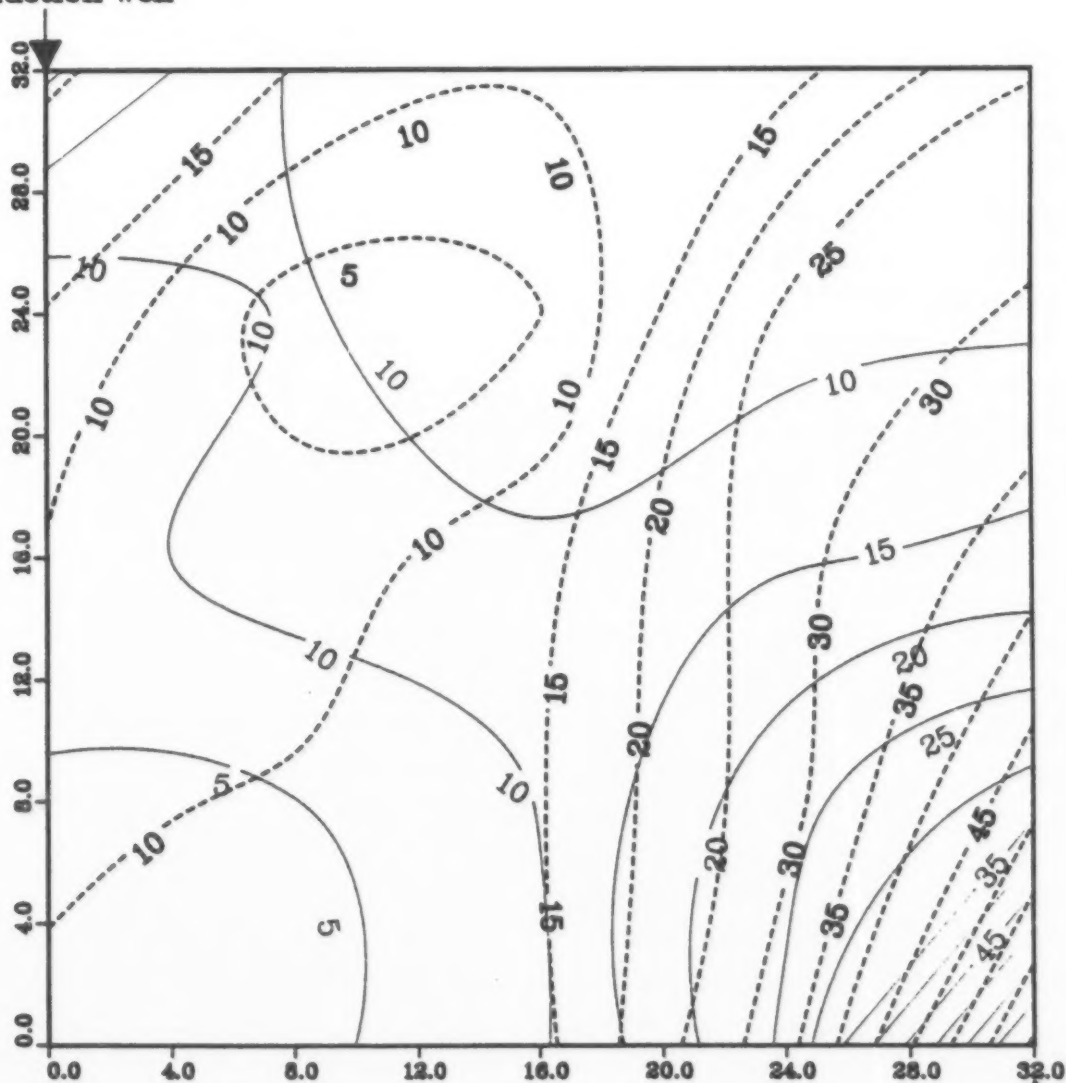


Figure A.251 : Run 64
Steamflood With Partial B.W. Barrier

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

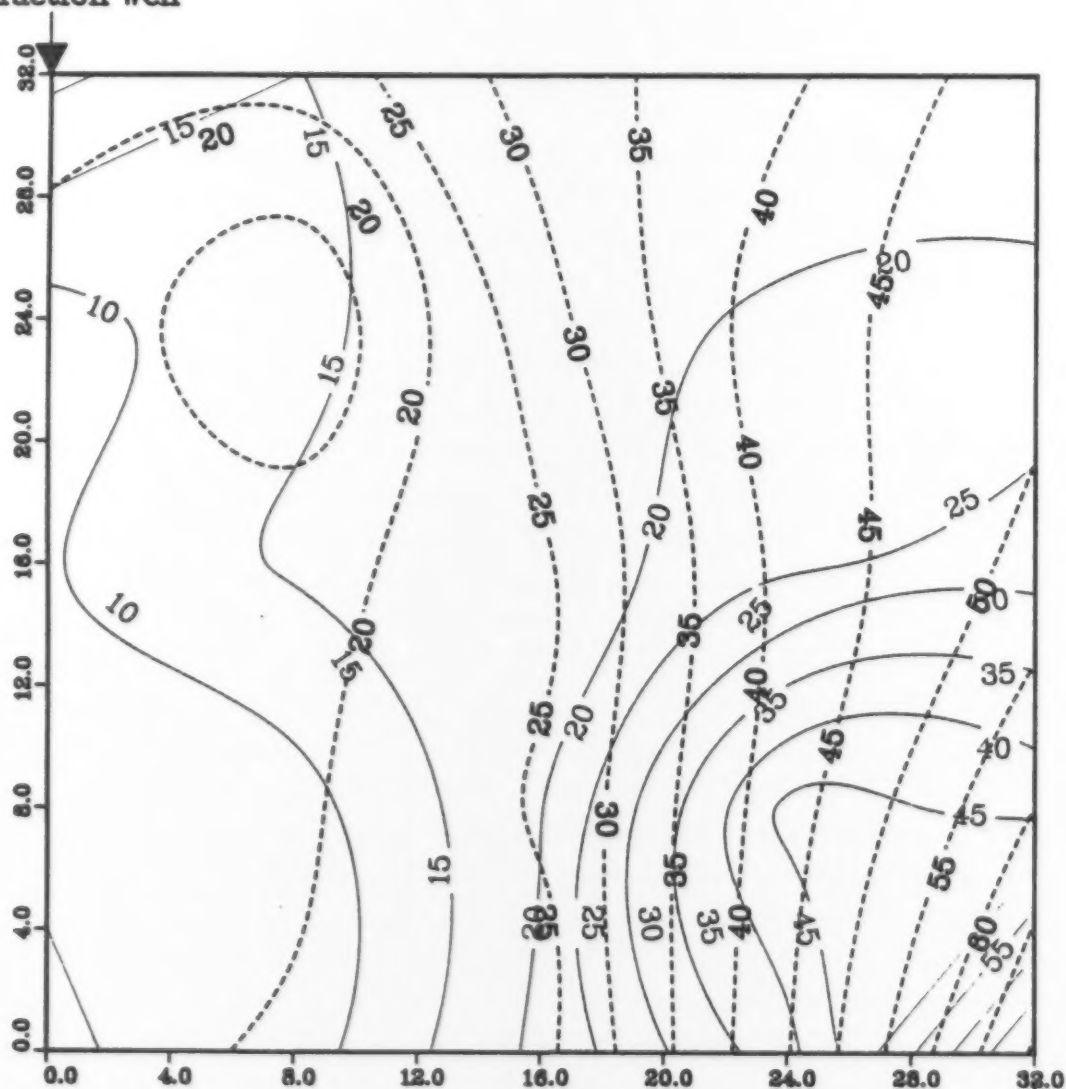
Lower Model Temperature (C)

Injection Well

Figure A.252 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 0.50 Pore Volumes Injected

Production Well



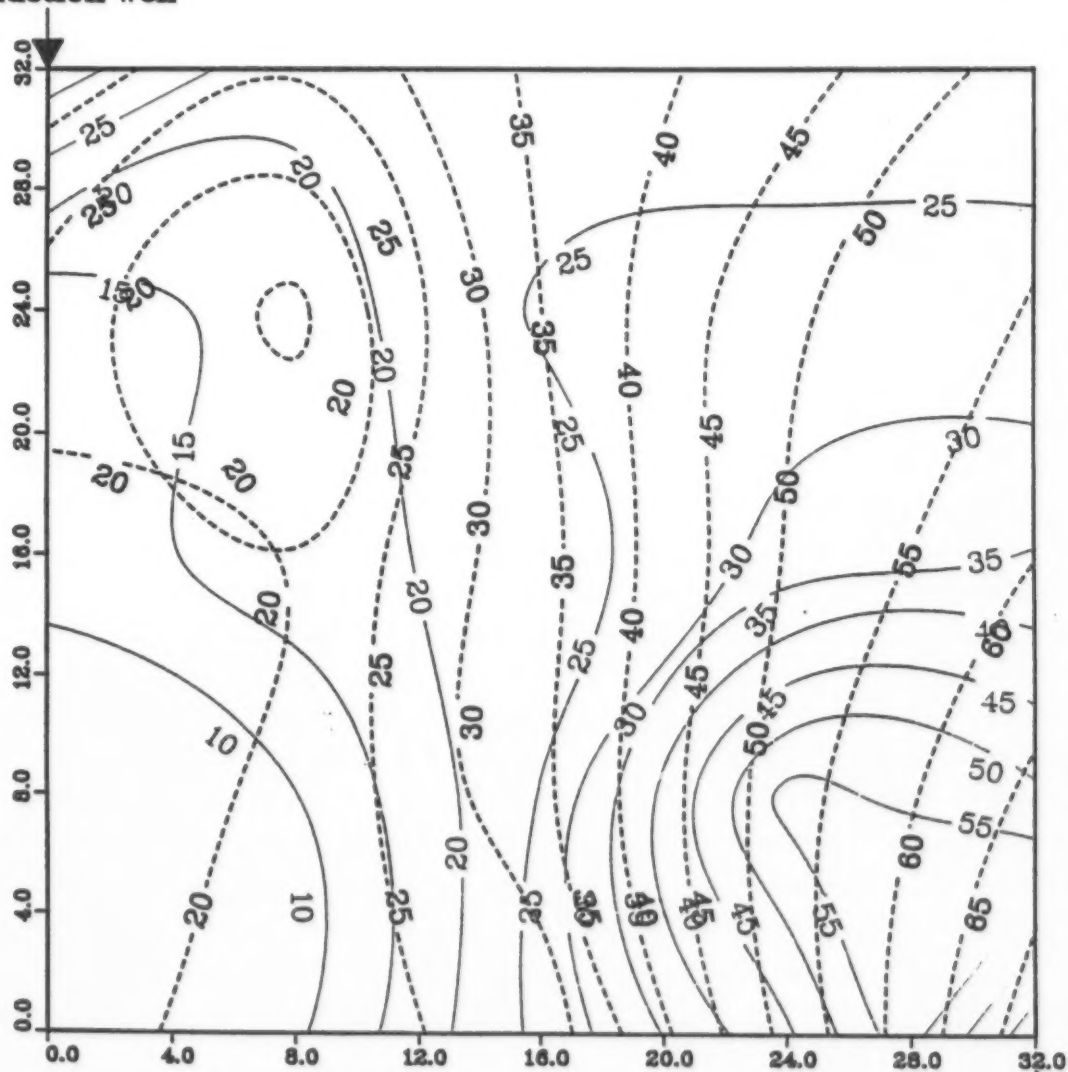
Upper Model Temperature (C)
 Lower Model Temperature (C)

Injection Well

Figure A.253 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

Figure A.254 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.00 Pore Volumes Injected

Production Well

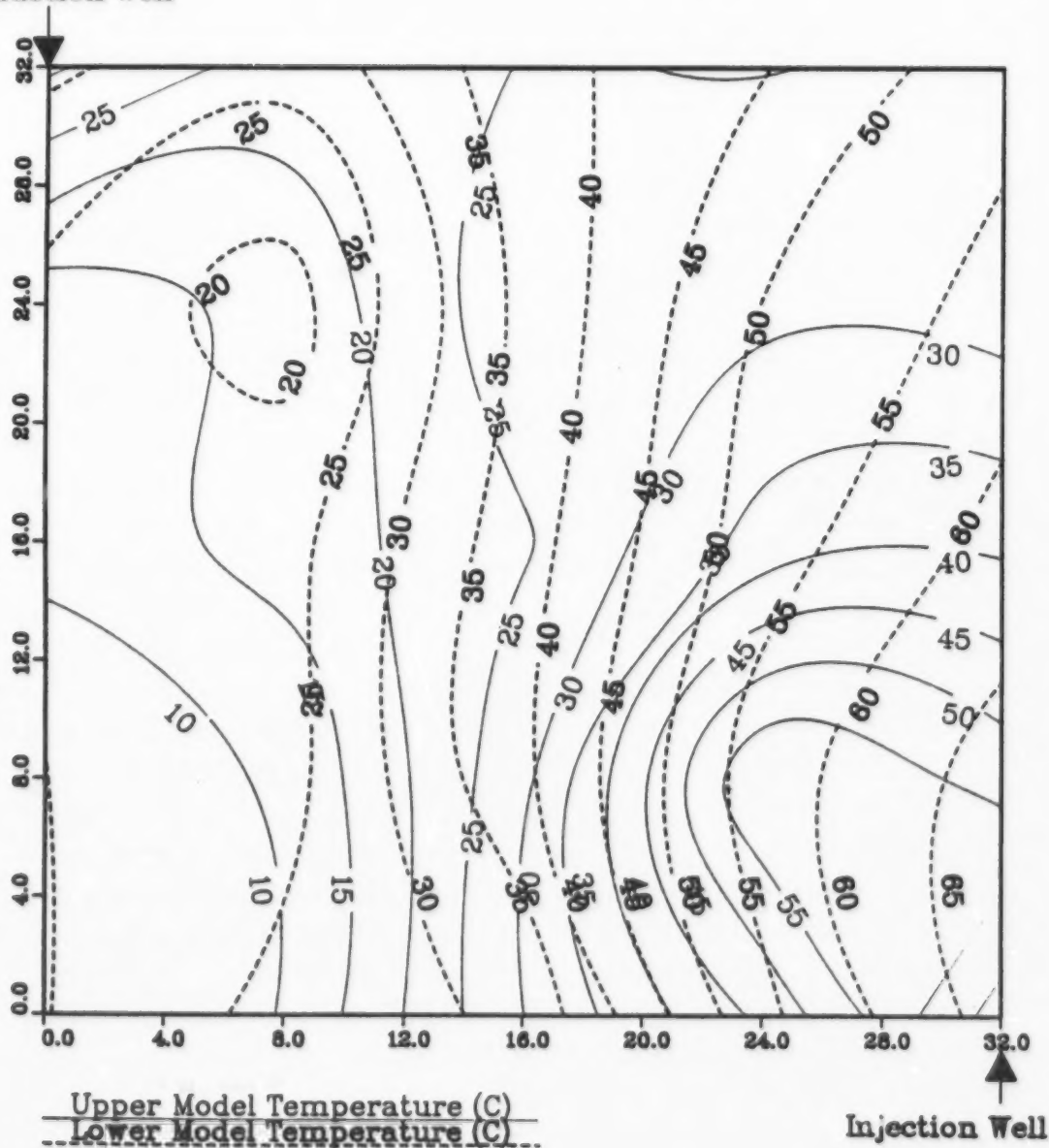
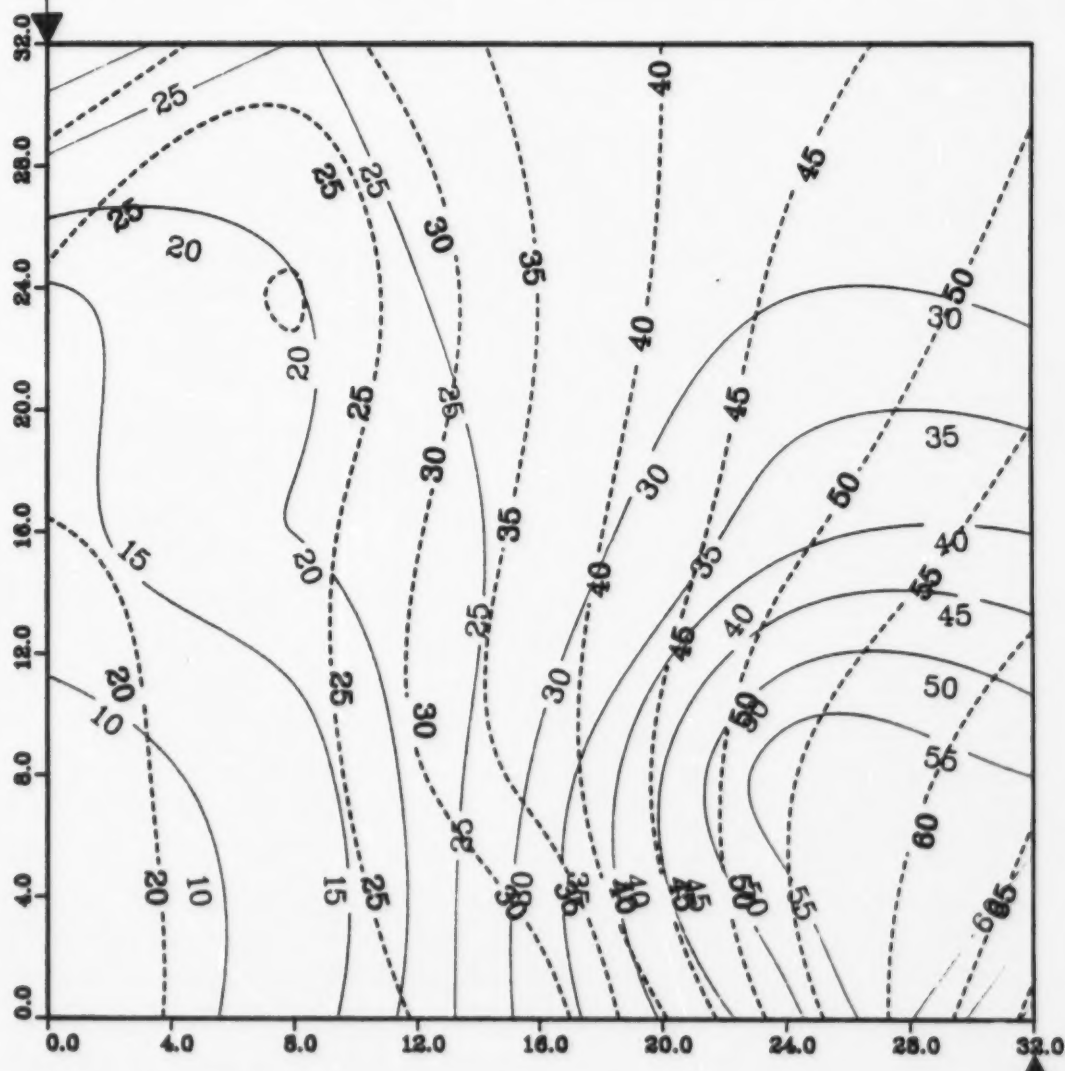


Figure A255 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

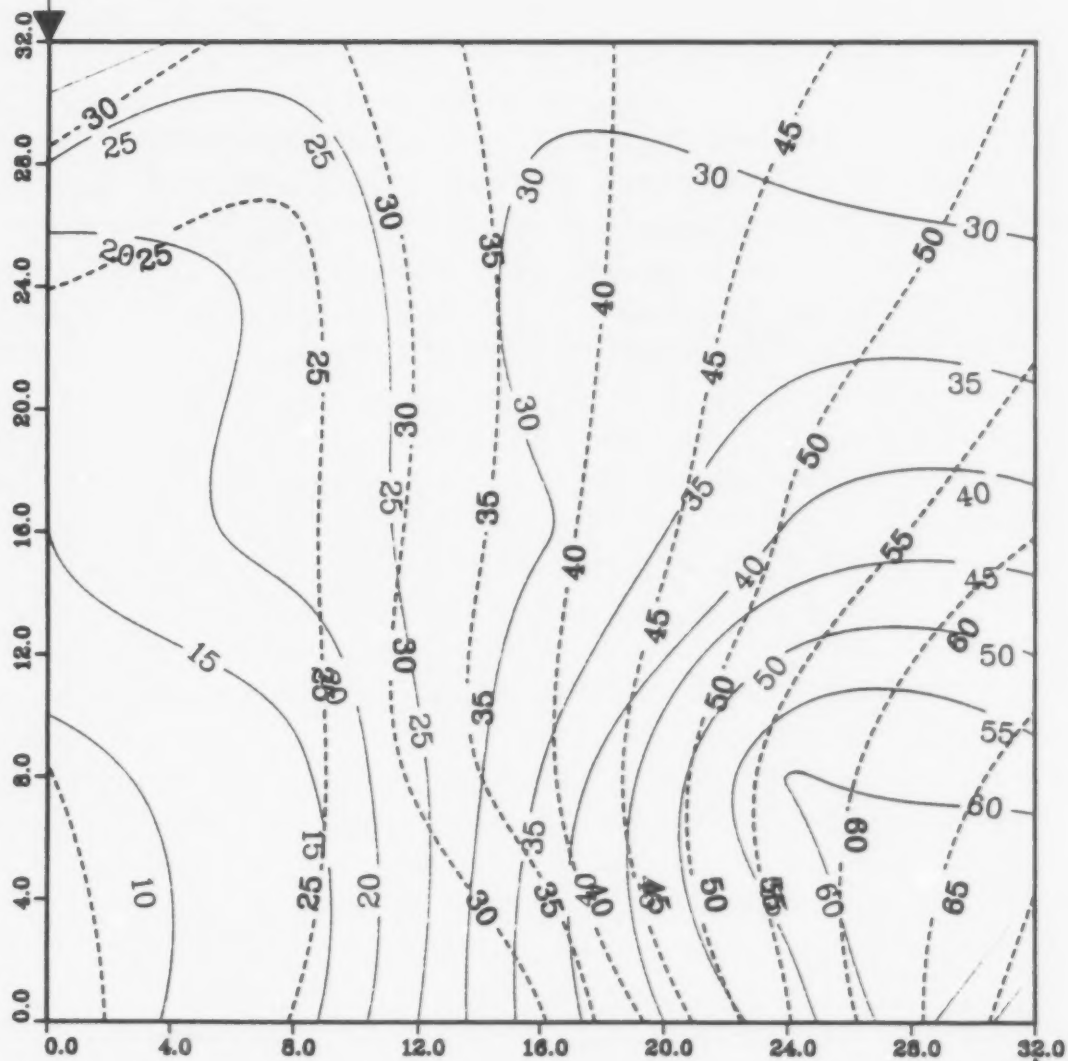
Lower Model Temperature (C)

Injection Well

Figure A.256 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

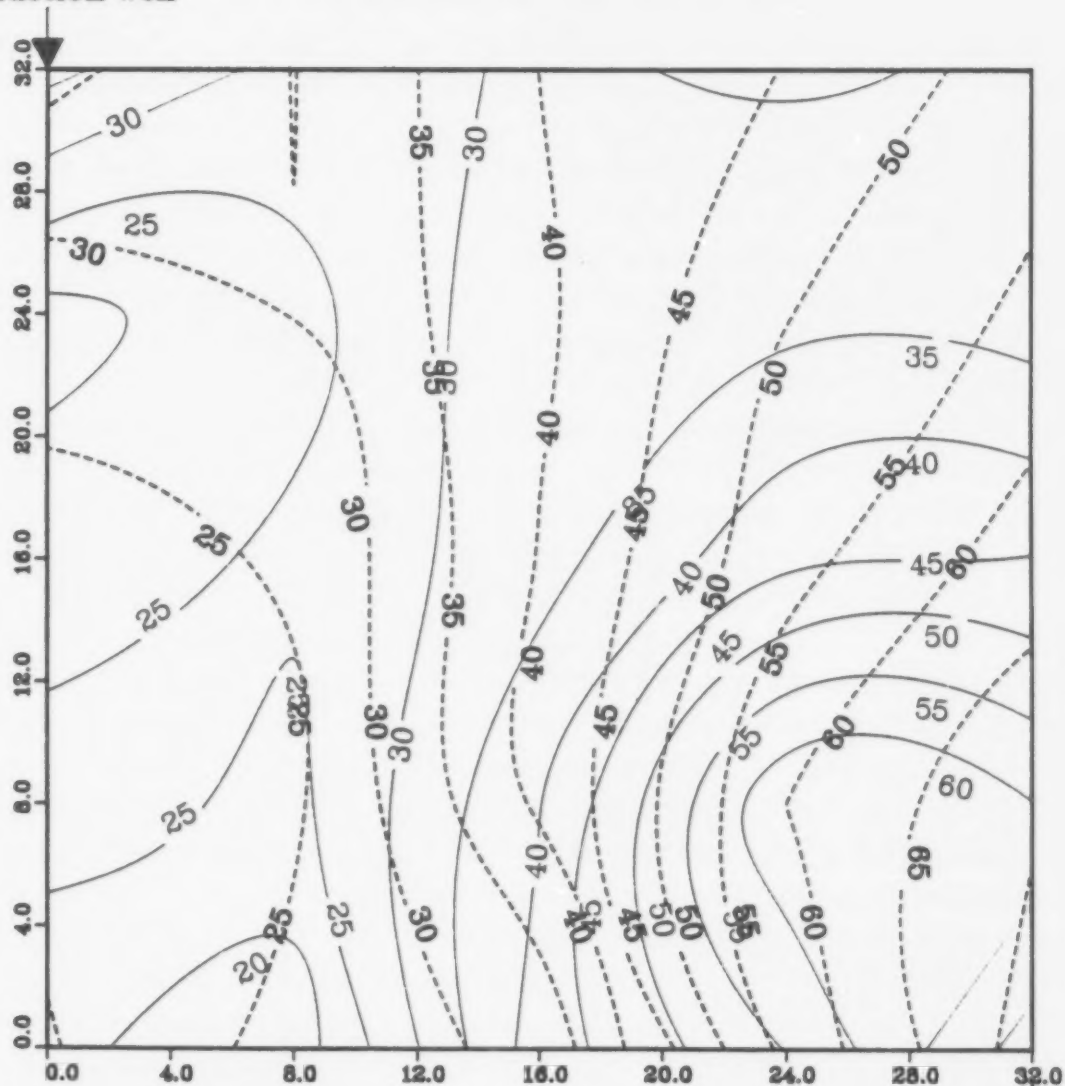
Lower Model Temperature (C)

Injection Well

Figure A.257 : Run 64
 Steamflood With Partial B.W. Barrier

Temperature Profile for
 1.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

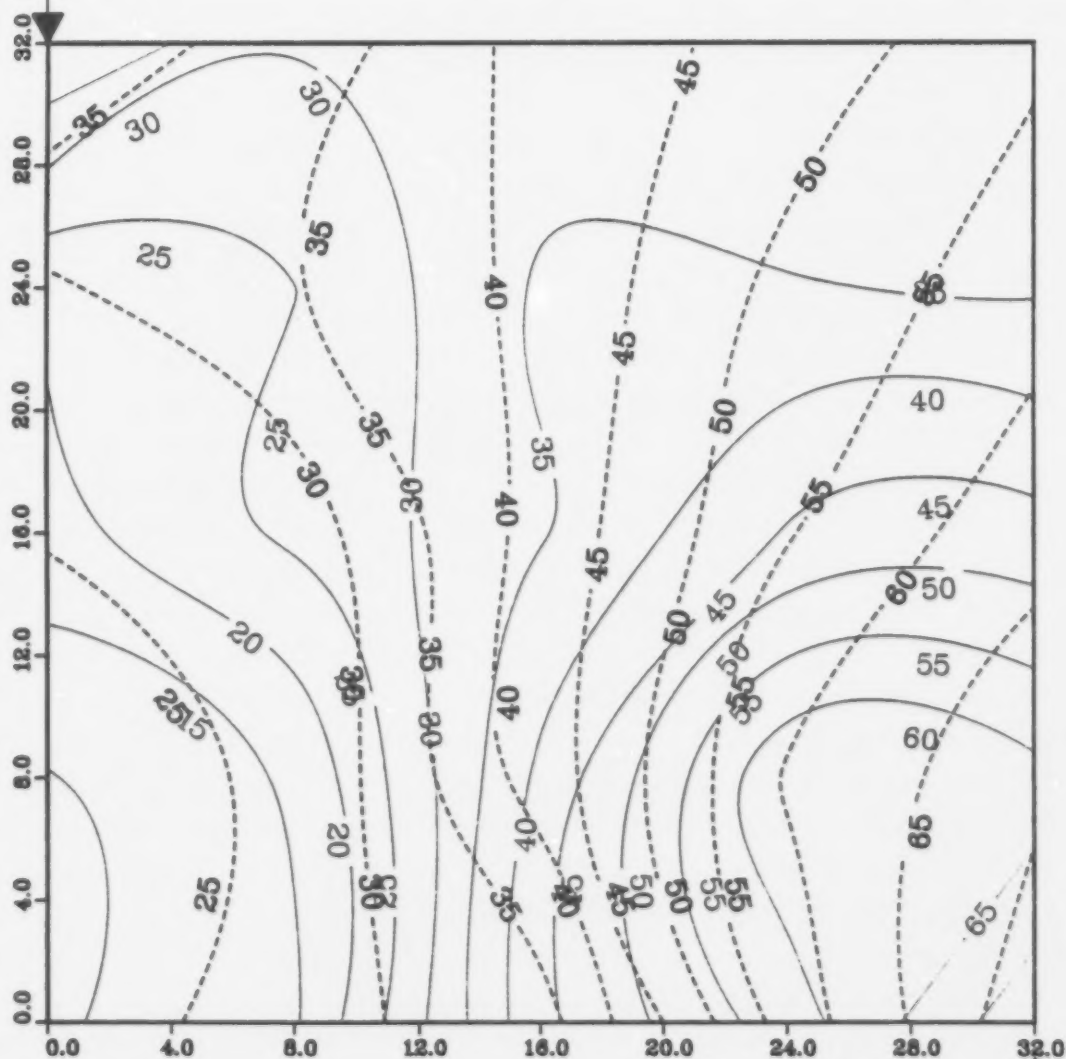
Lower Model Temperature (C)

Injection Well

Figure A.258 : Run 64
Steamflood With Partial B.W. Barrier

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

**Figure A.259 :Run 64 Temp Profile
Injector to Producer Cross-Section**
0.25 Pore Volumes Injected.

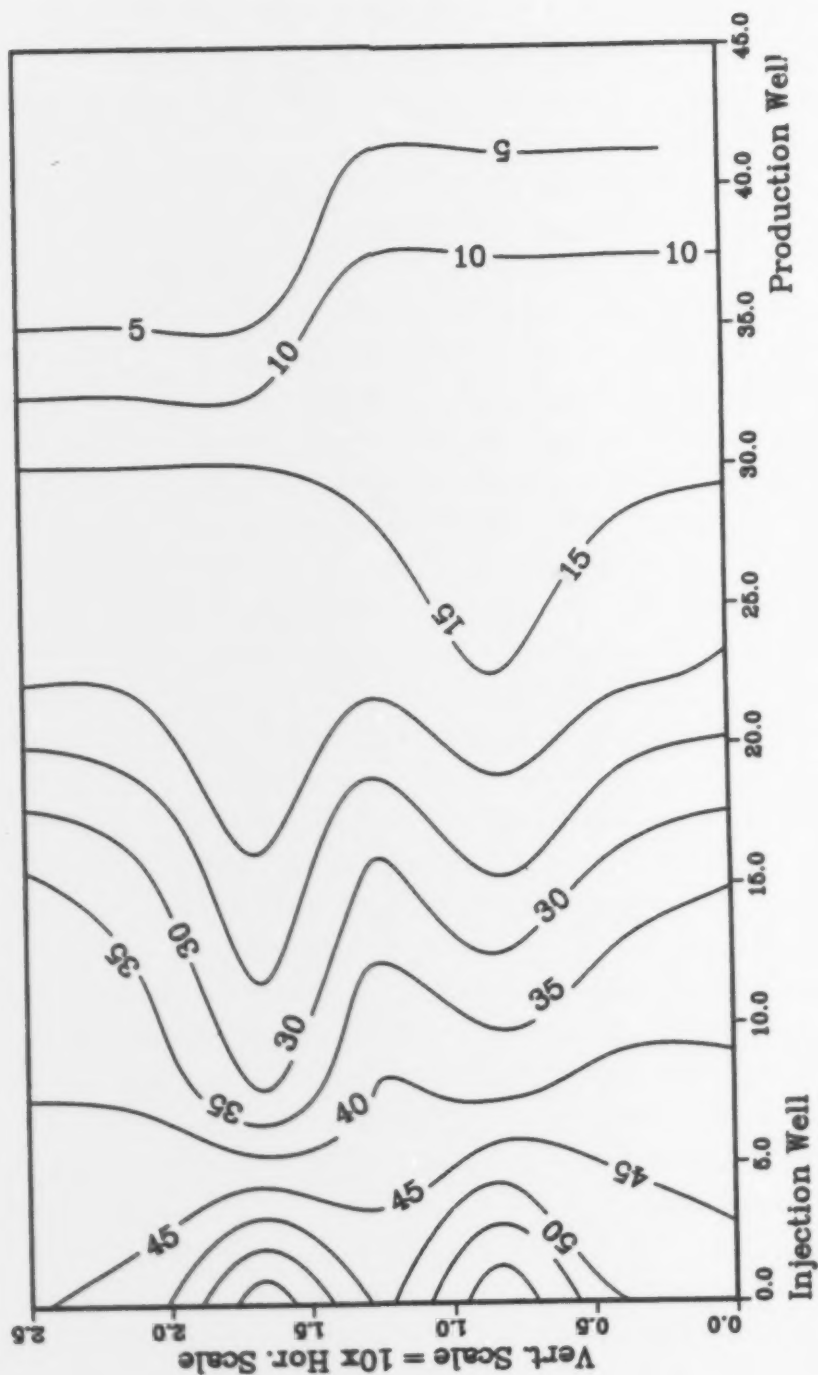


**Figure A.260 :Run 64 Temp Profile
Injector to Producer Cross-Section
0.50 Pore Volumes Injected.**

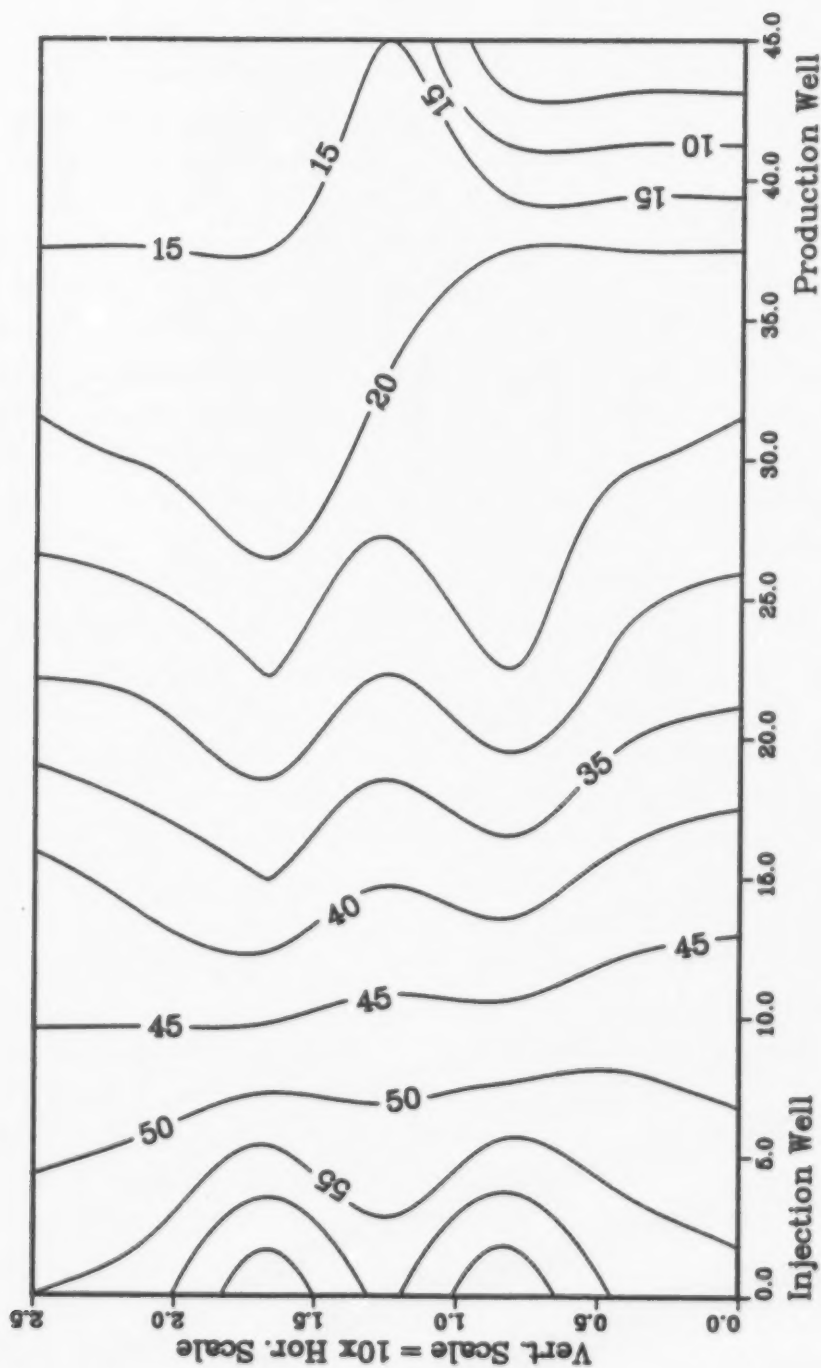


**Figure A.261 :Run 64 Temp Profile
Injector to Producer Cross-Section**
0.76 Pore Volumes Injected.

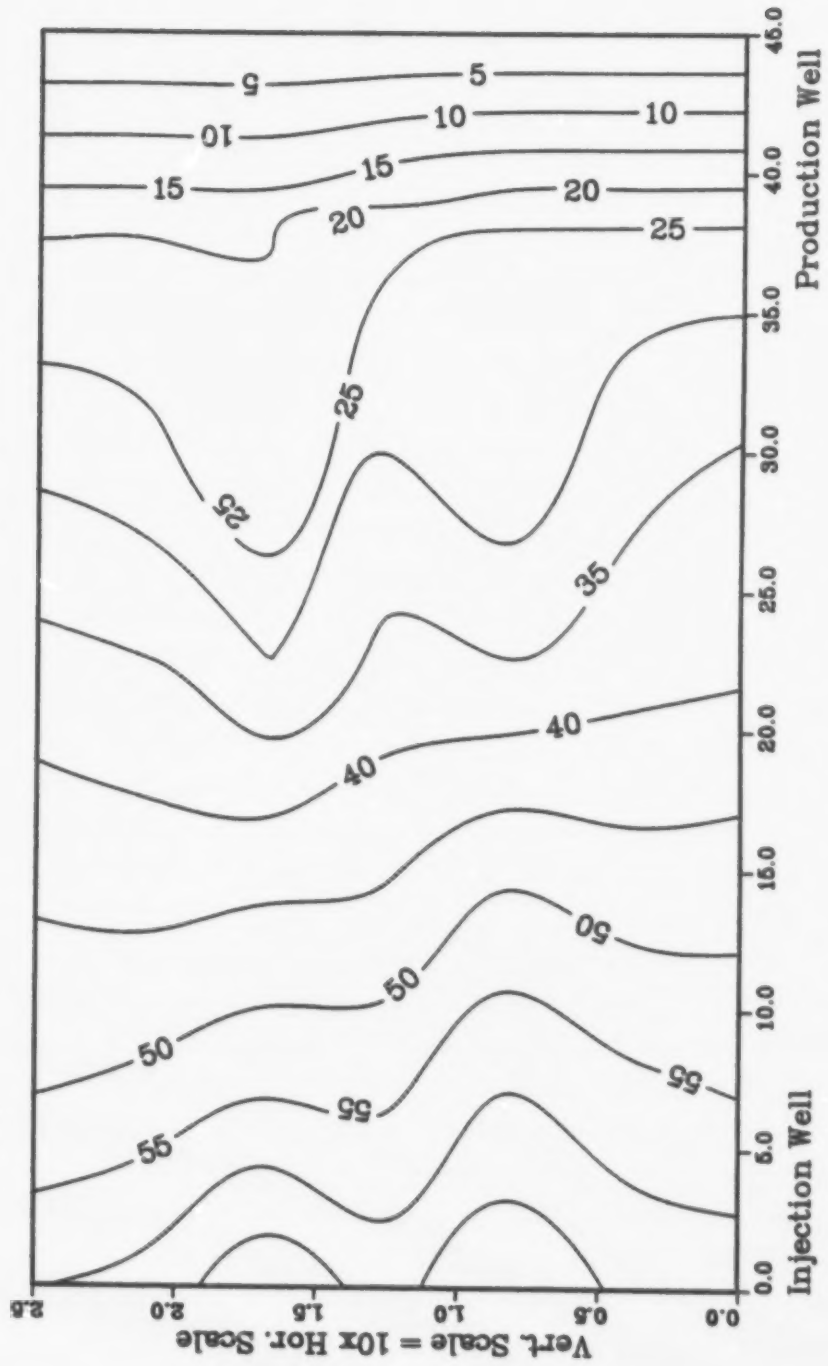


Figure A.263 : Run 47A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
0.25 Pore Volumes Injected

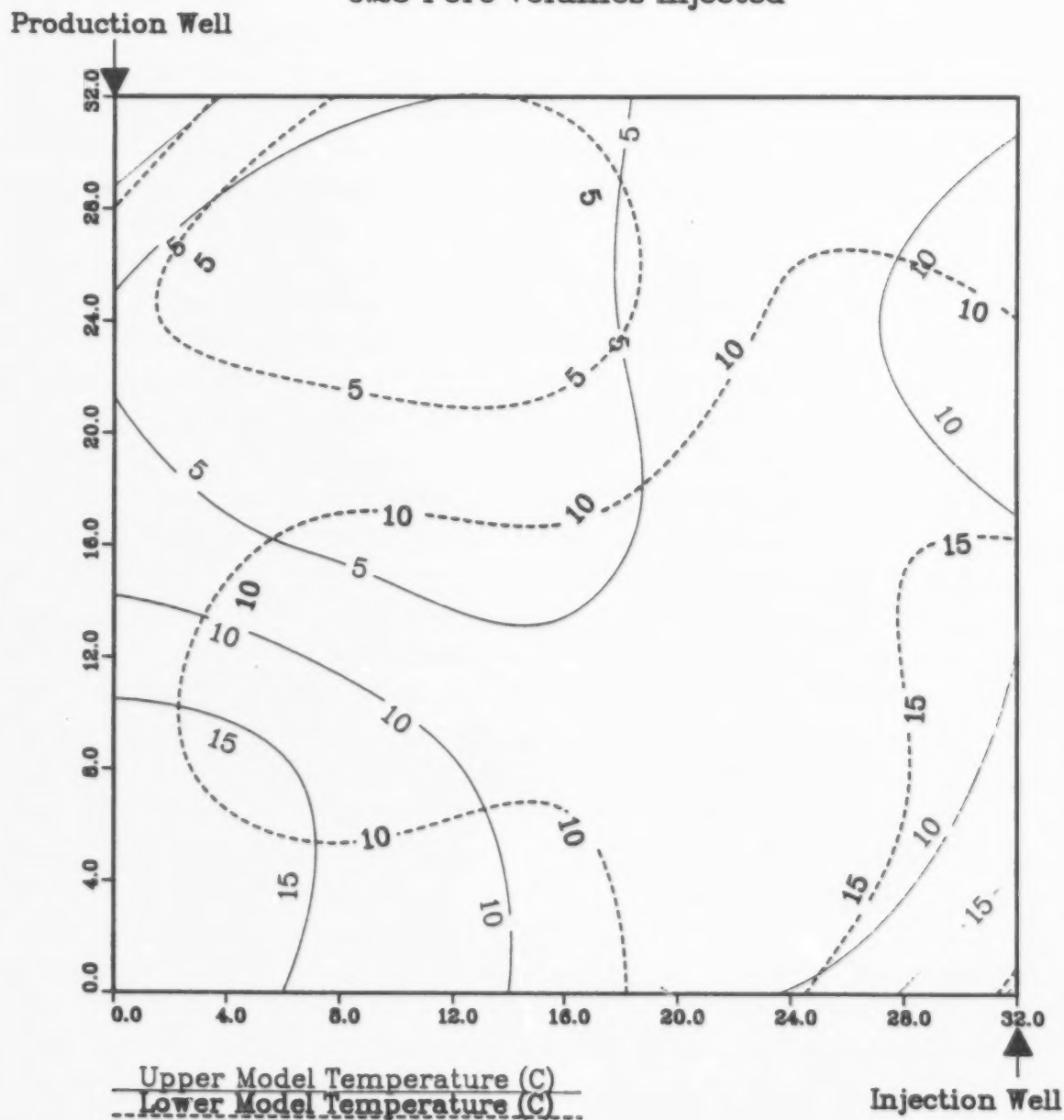


Figure A.264 : Run 47A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
0.50 Pore Volumes Injected

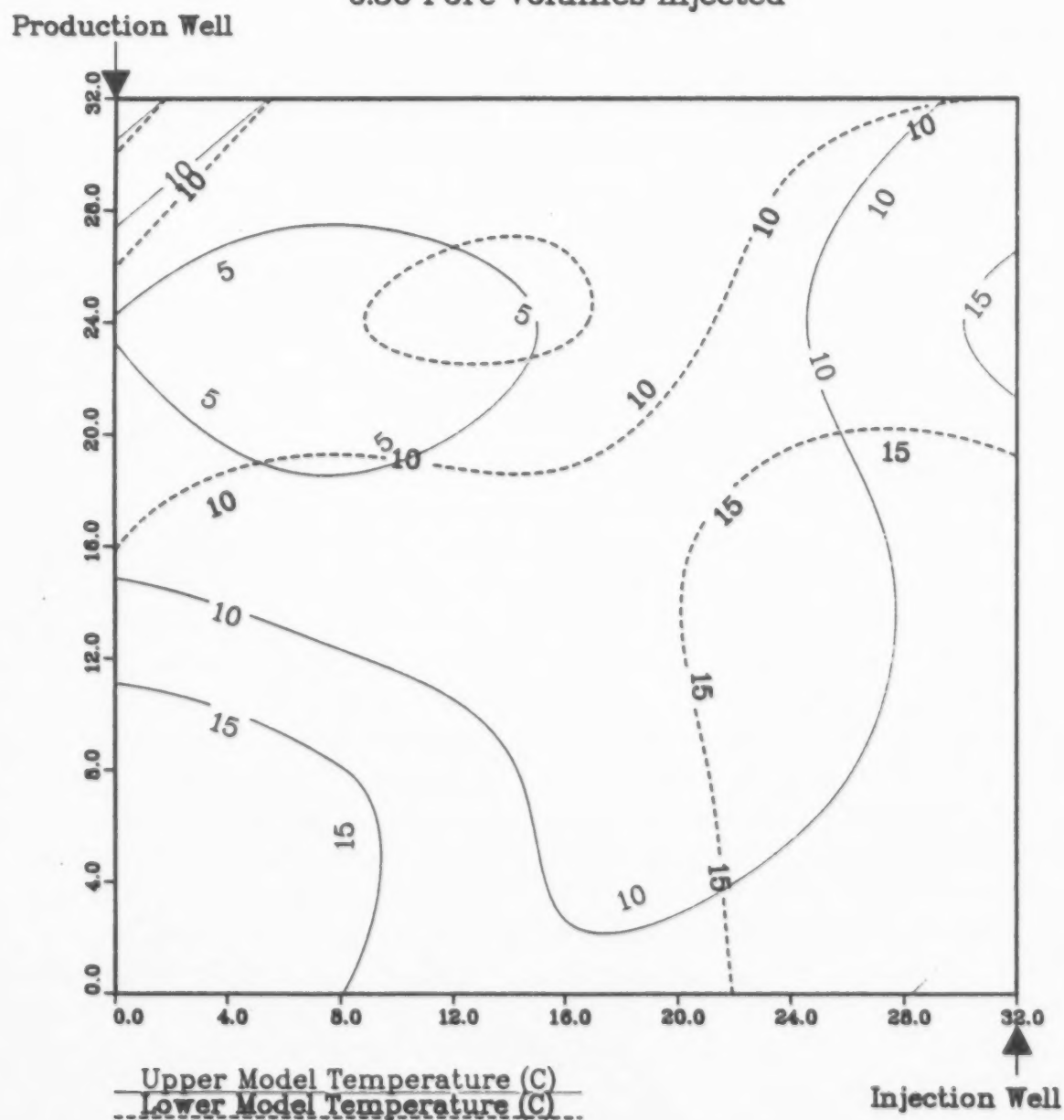
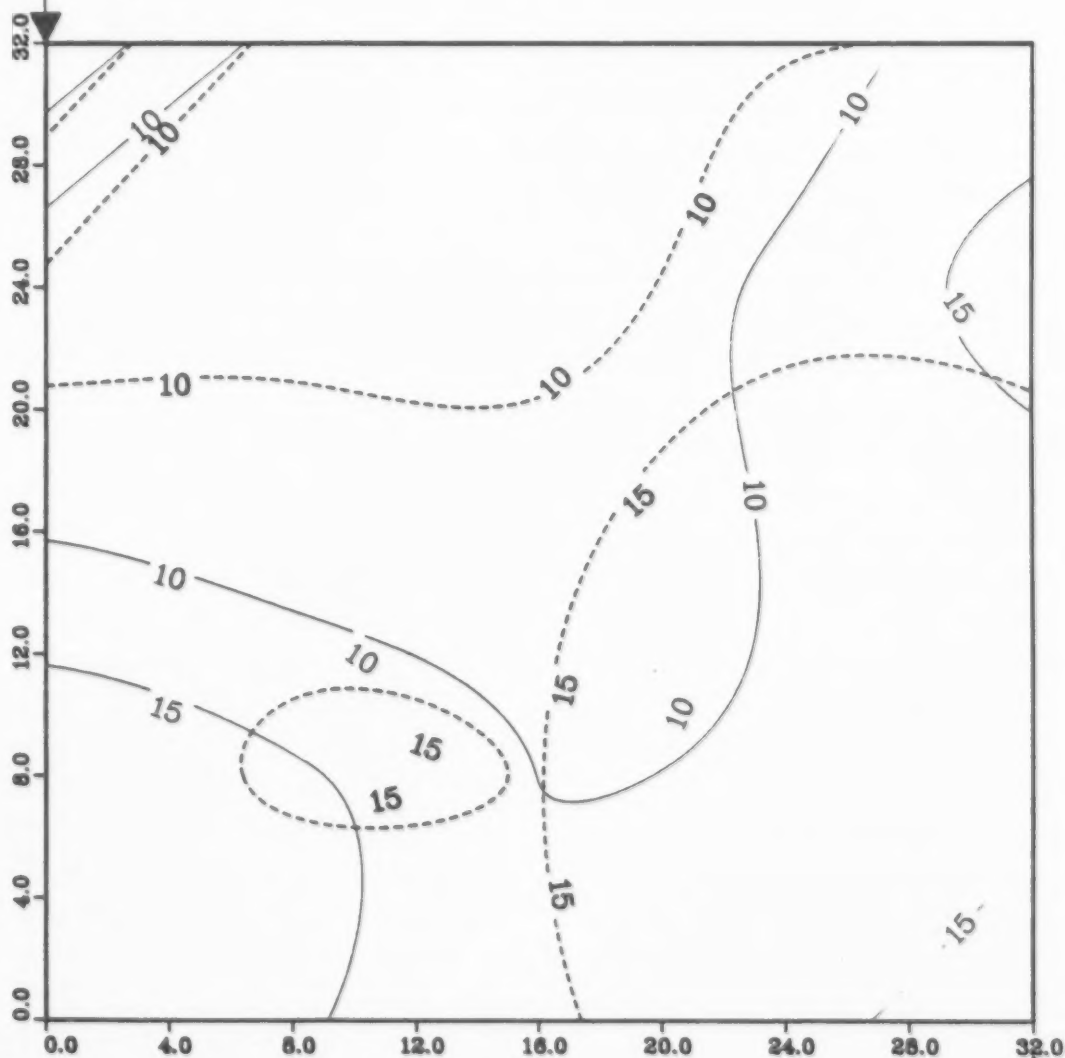


Figure A.265 : Run 47A
Waterflood Prior to Solvent--Steamflood

Temperature Profile for
0.75 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

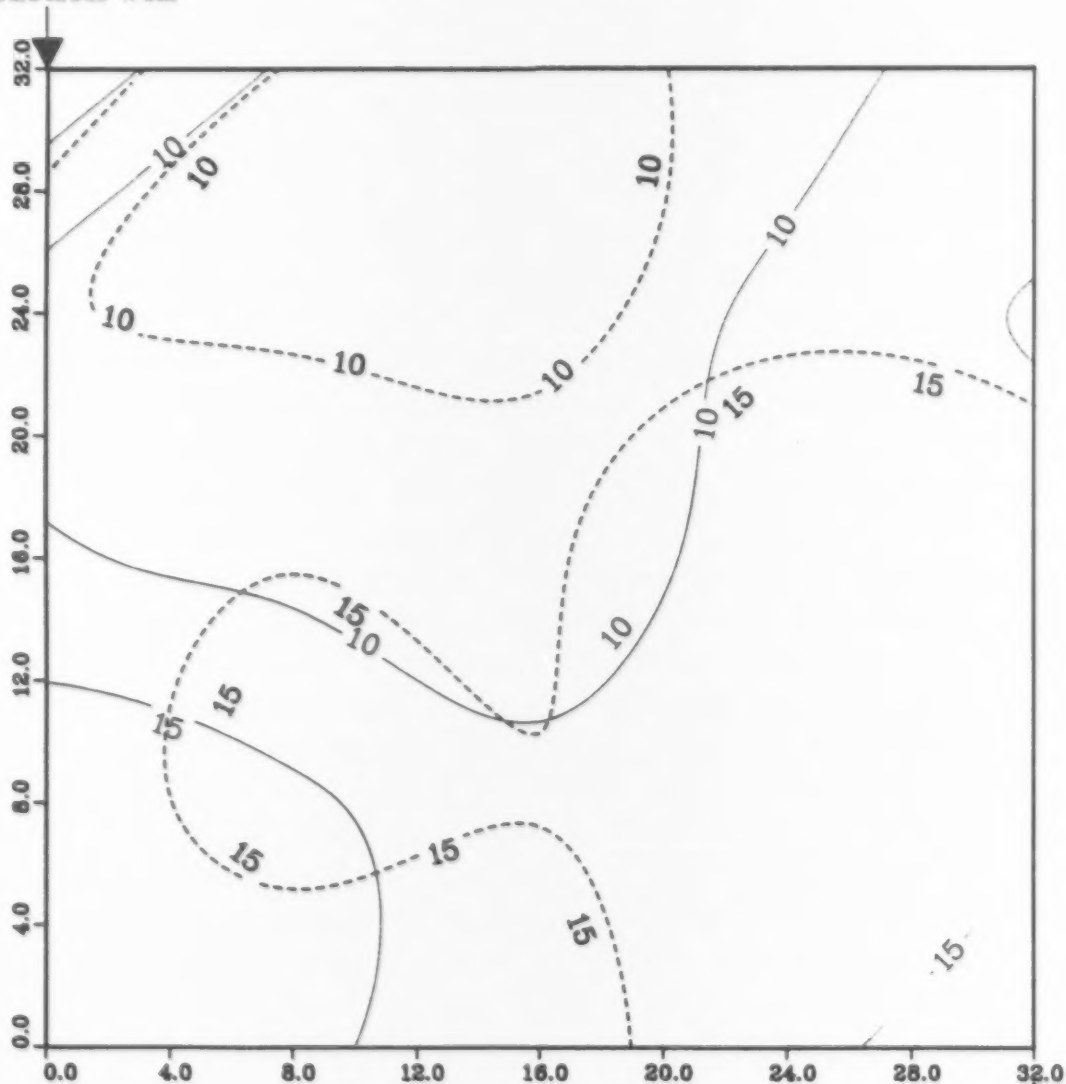
Lower Model Temperature (C)

Injection Well

Figure A.266 : Run 47A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.267 : Run 47A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for 1.50 Pore Volumes Injected

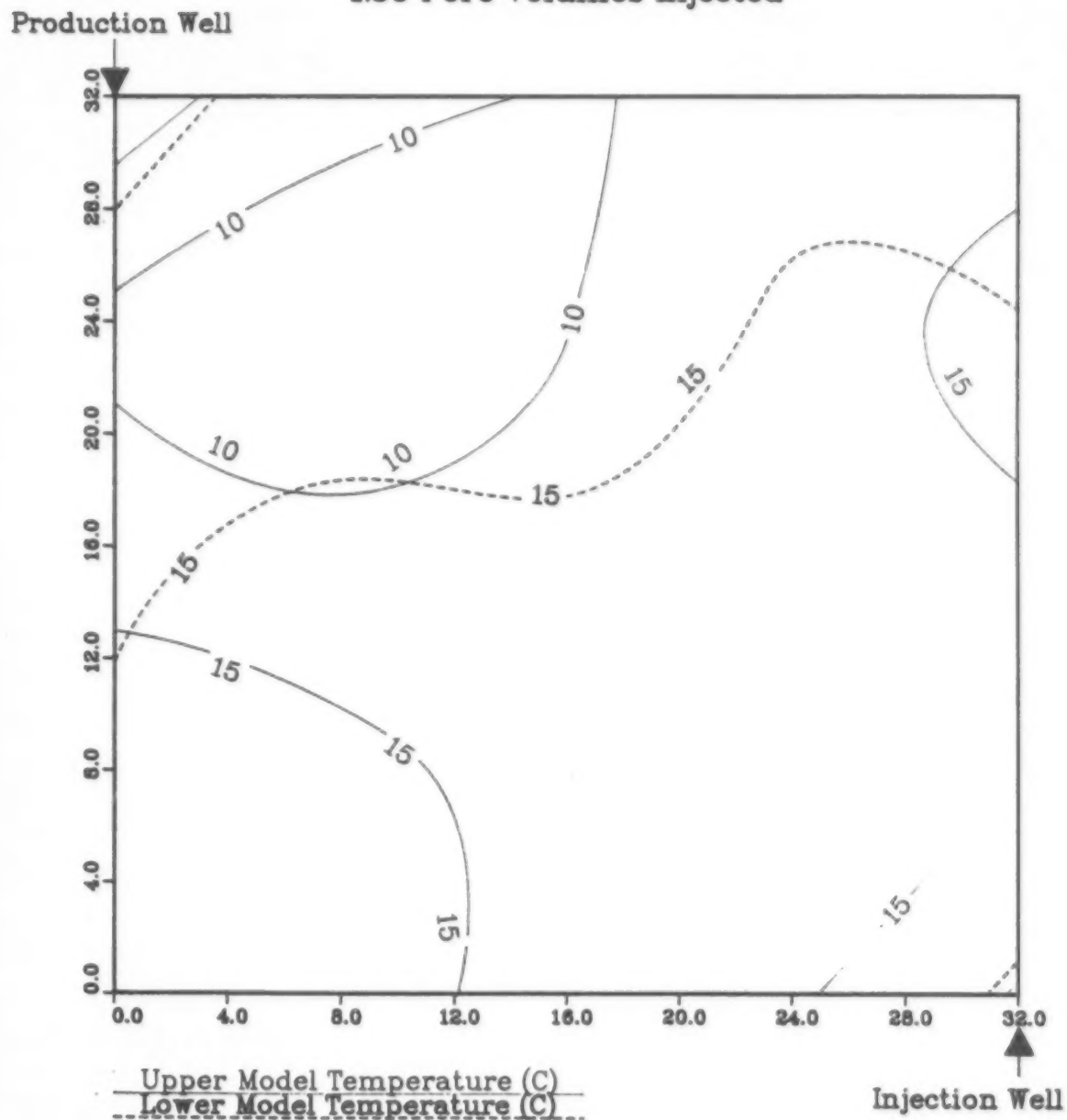
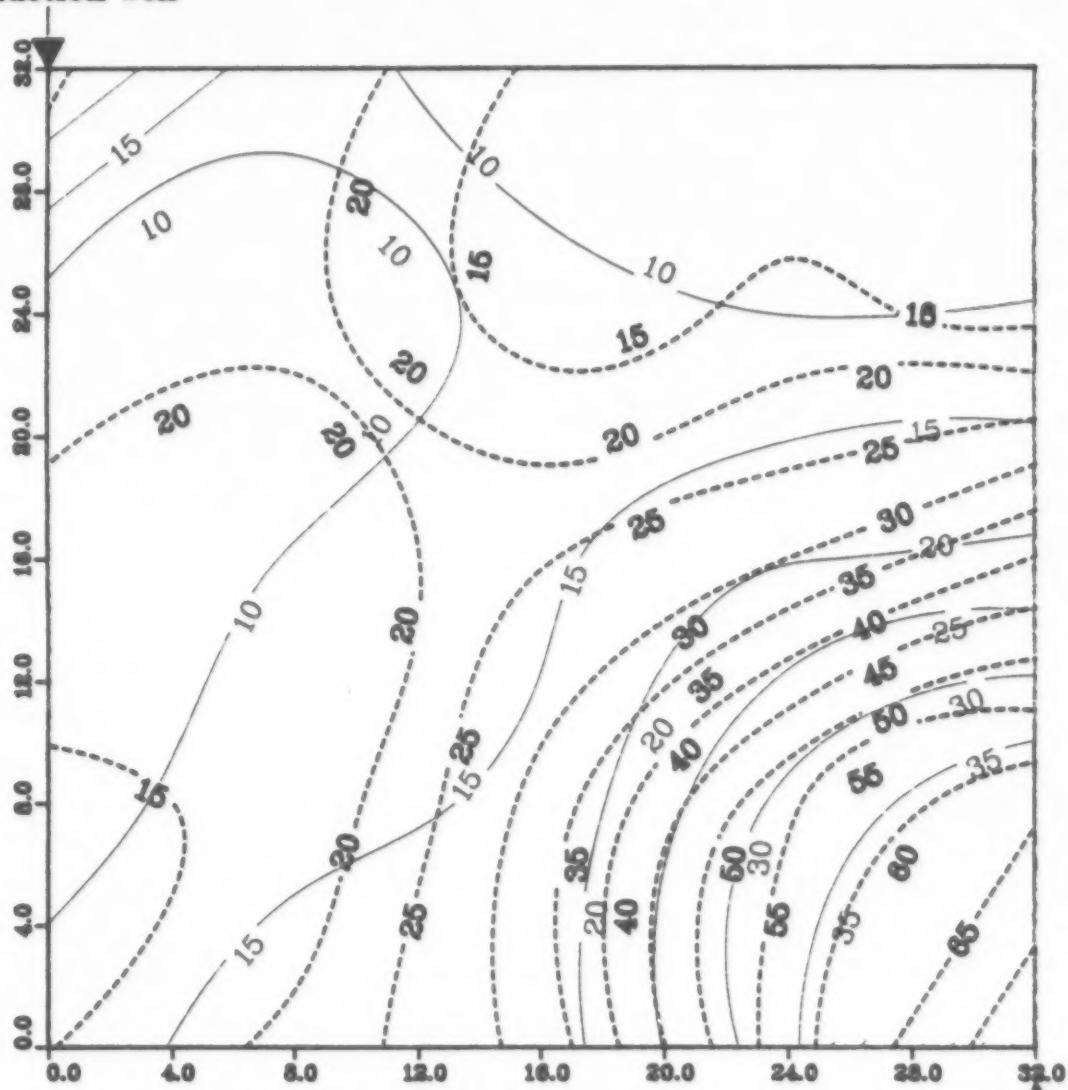


Figure A.268 : Run 47B
Solvent-Steamflood After a Waterflood

Temperature Profile for
2.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

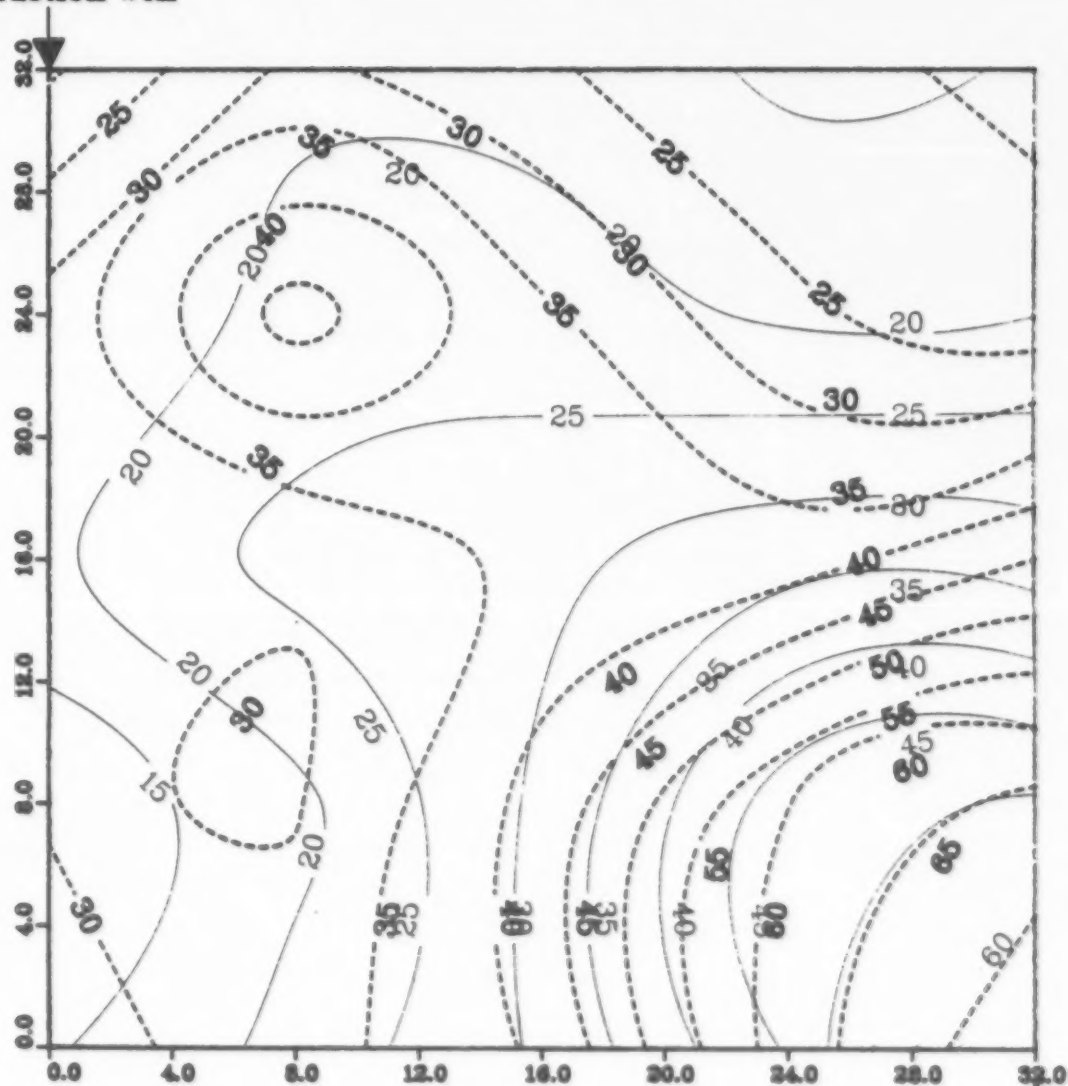
Lower Model Temperature (C)

Injection Well

Figure A.269 : Run 47B
Solvent-Steamflood After a Waterflood

Temperature Profile for
2.50 Pore Volumes Injected

Production Well



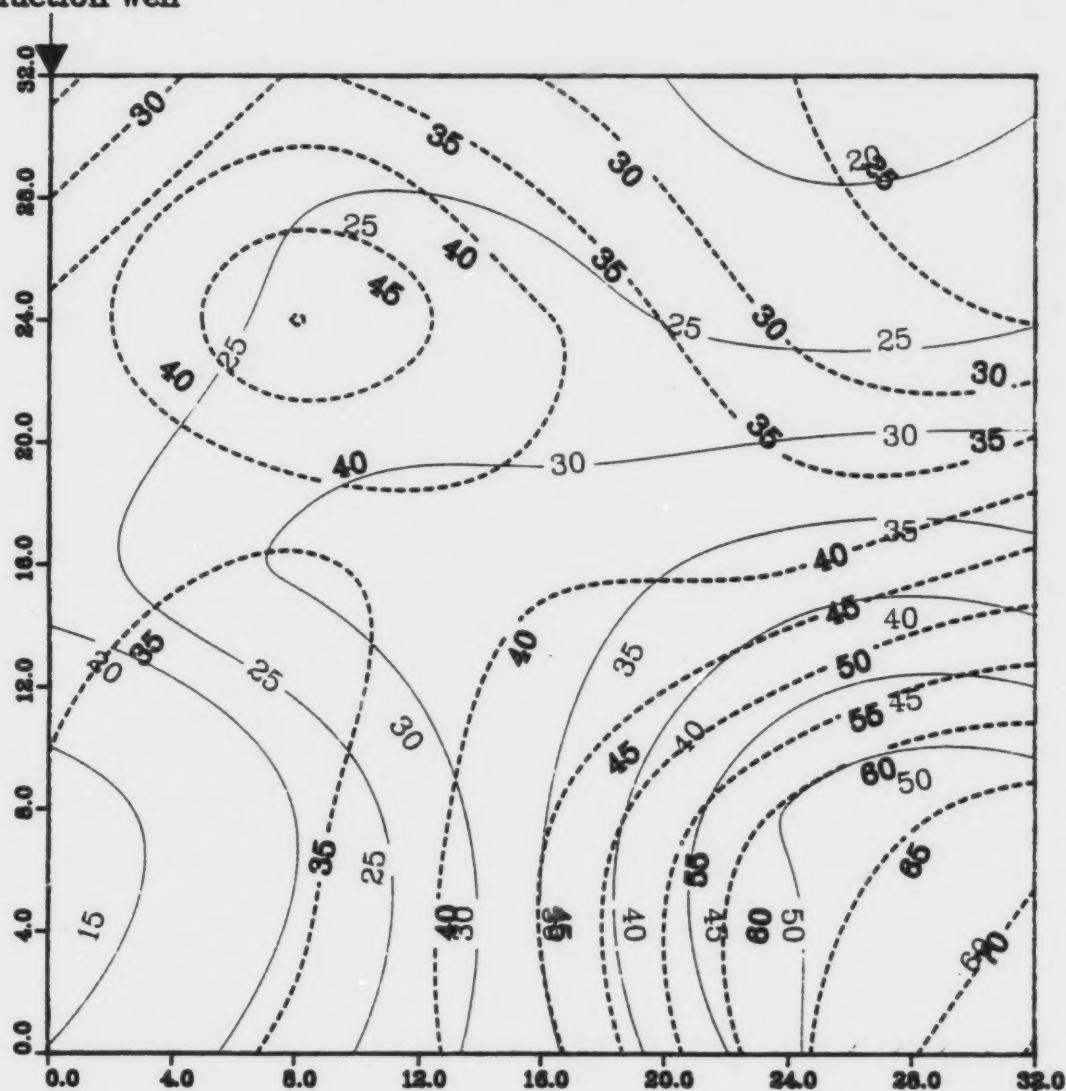
— Upper Model Temperature (C)
--- Lower Model Temperature (C)

Injection Well

Figure A.270 : Run 47B
Solvent-Steamflood After a Waterflood

Temperature Profile for
3.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

**Figure A.271 :Run 47 Temp Profile
Injector to Producer Cross-Section
2.00 Pore Volumes Injected.**

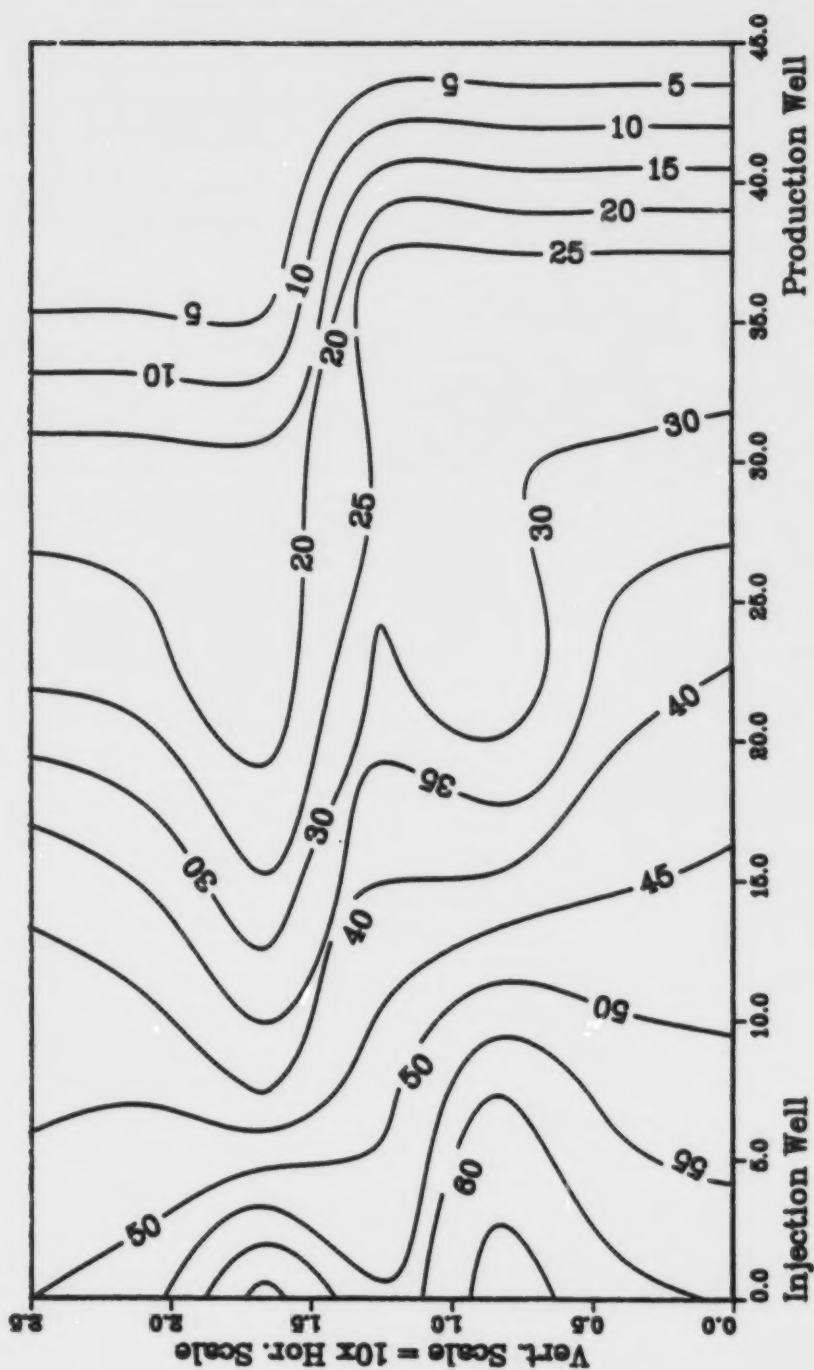


**Figure A.272 :Run 47 Temp Profile
Injector to Producer Cross-Section
2.50 Pore Volumes Injected.**

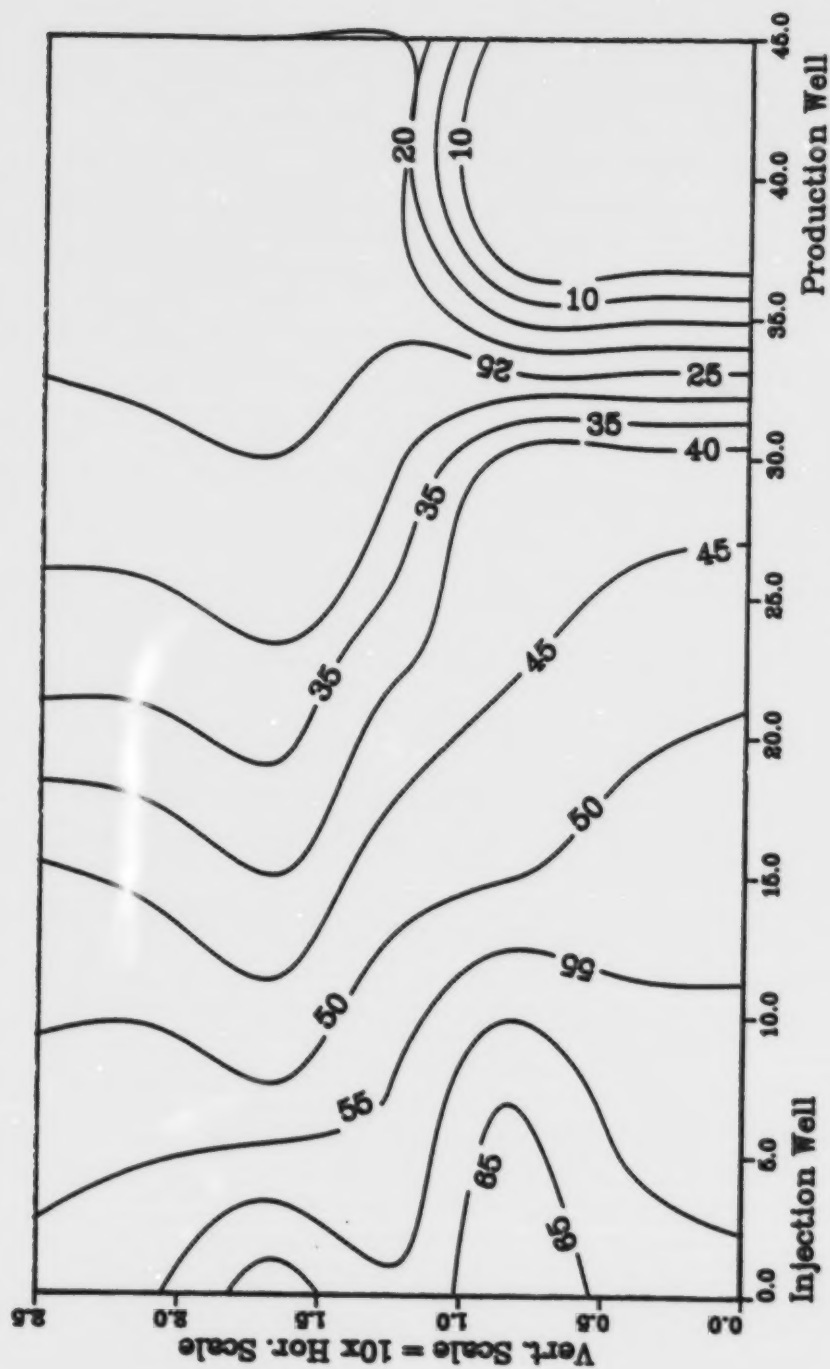


**Figure A.273 :Run 47 Temp Profile
Injector to Producer Cross-Section**
3.00 Pore Volumes Injected.

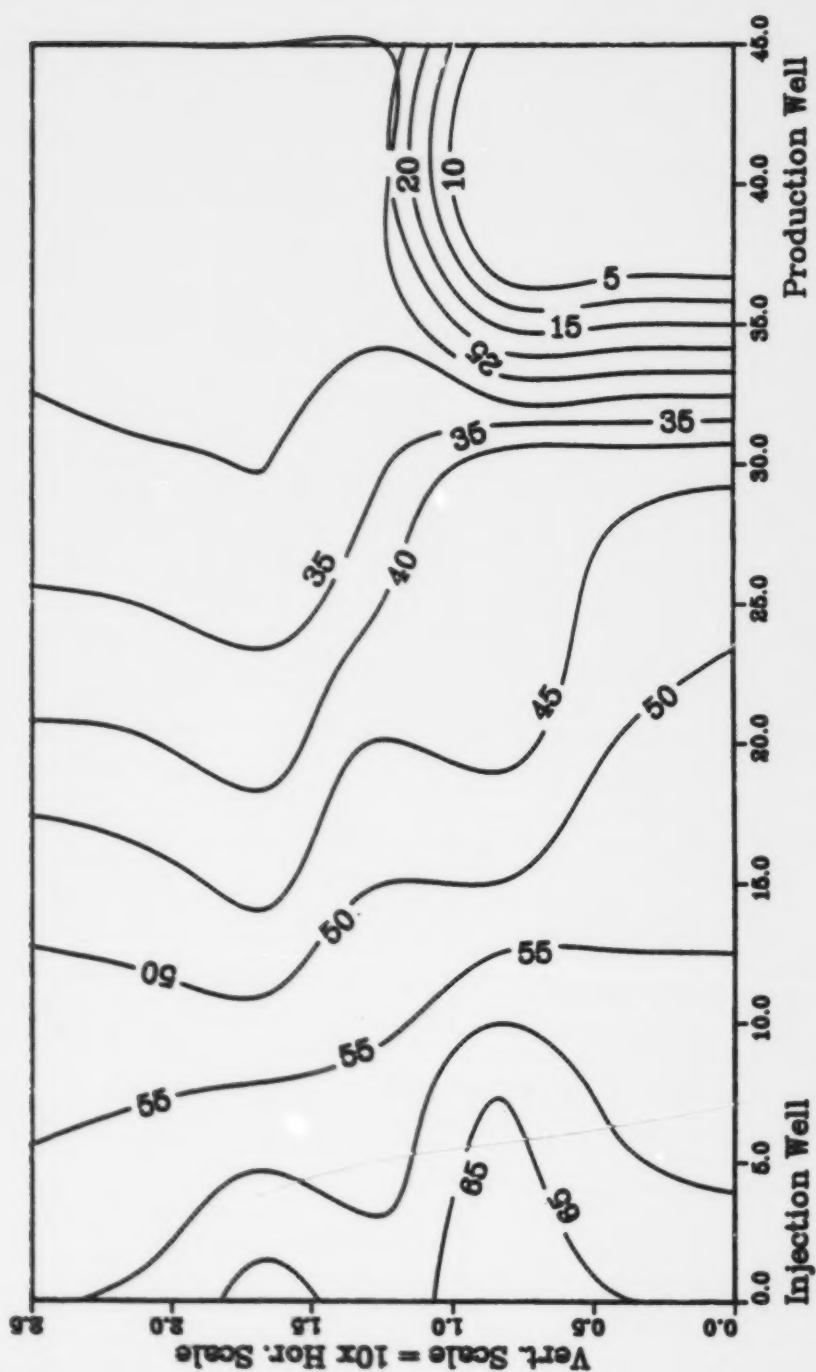
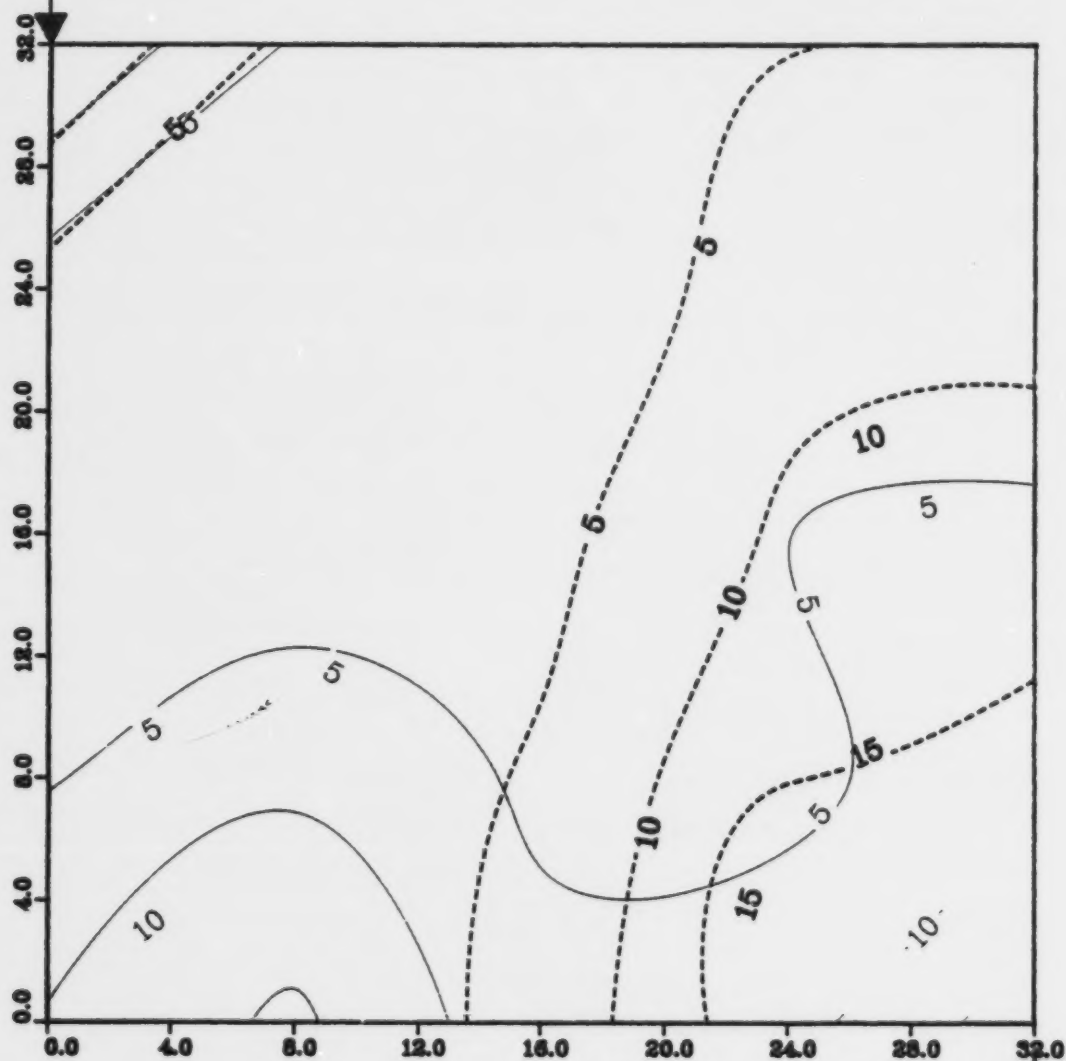


Figure A.274 : Run 48A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
0.25 Pore Volumes Injected

Production Well



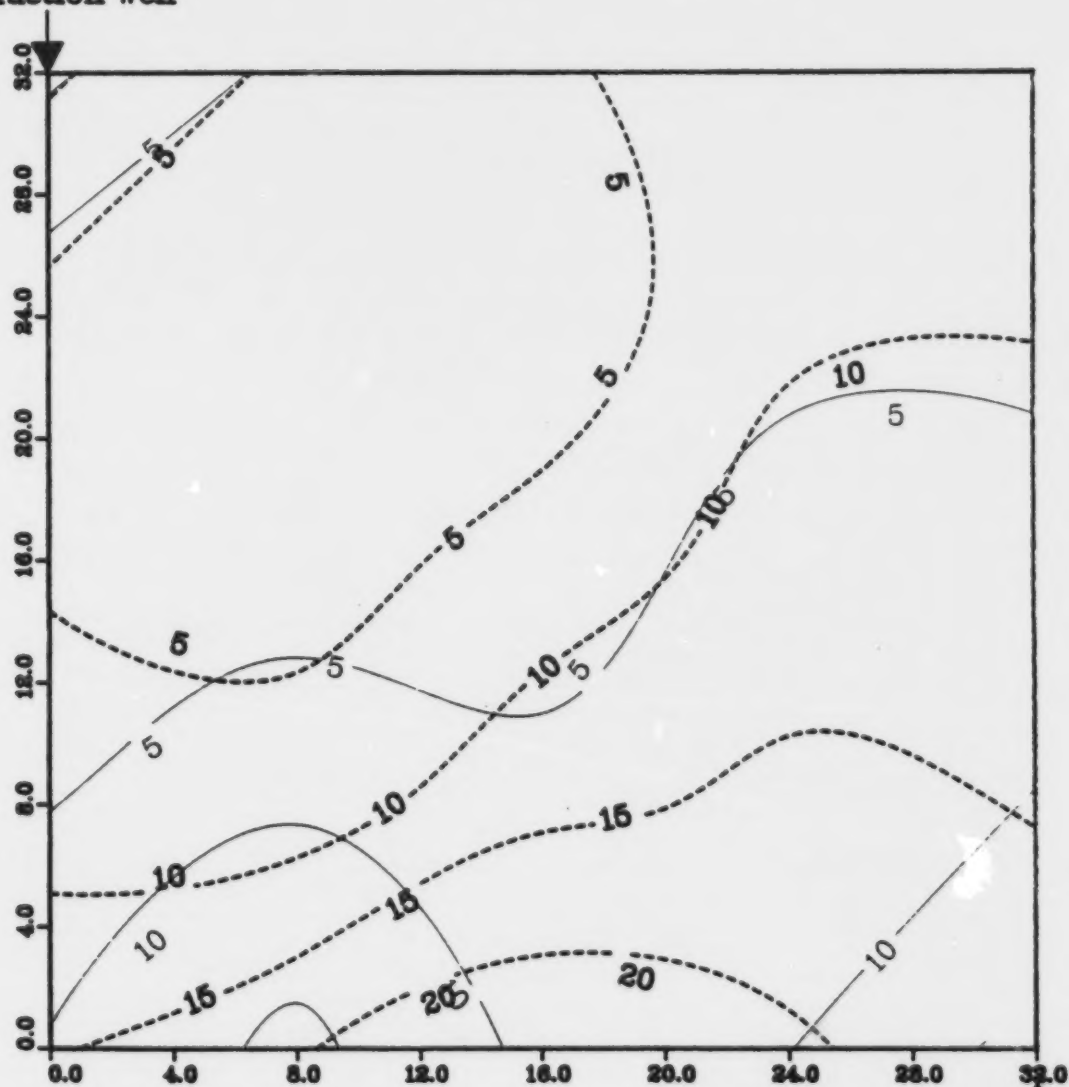
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.275 : Run 48A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
0.50 Pore Volumes Injected

Production Well



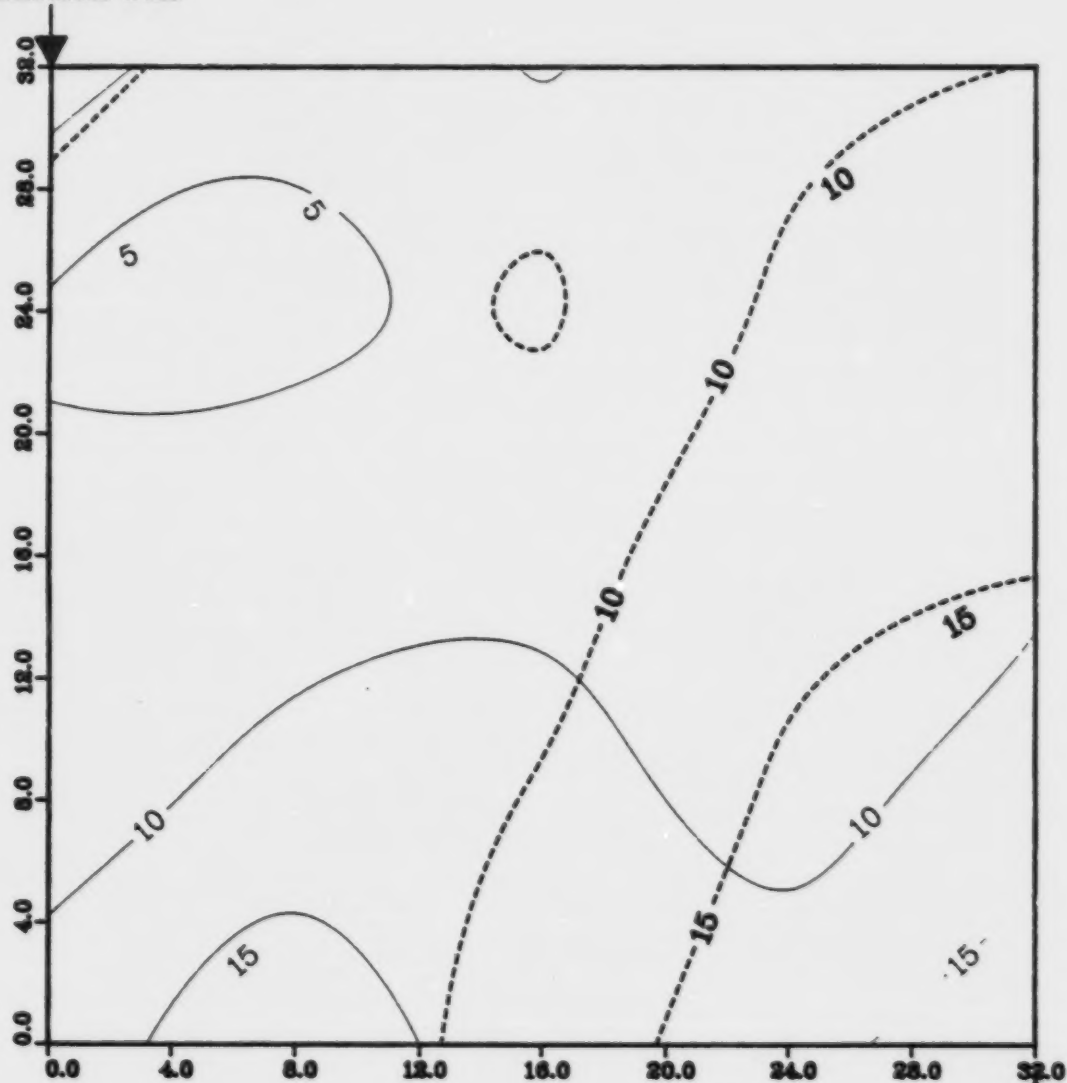
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.276 : Run 48A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
1.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A.277 : Run 48A
Waterflood Prior to Solvent-Steamflood

Temperature Profile for
1.50 Pore Volumes Injected

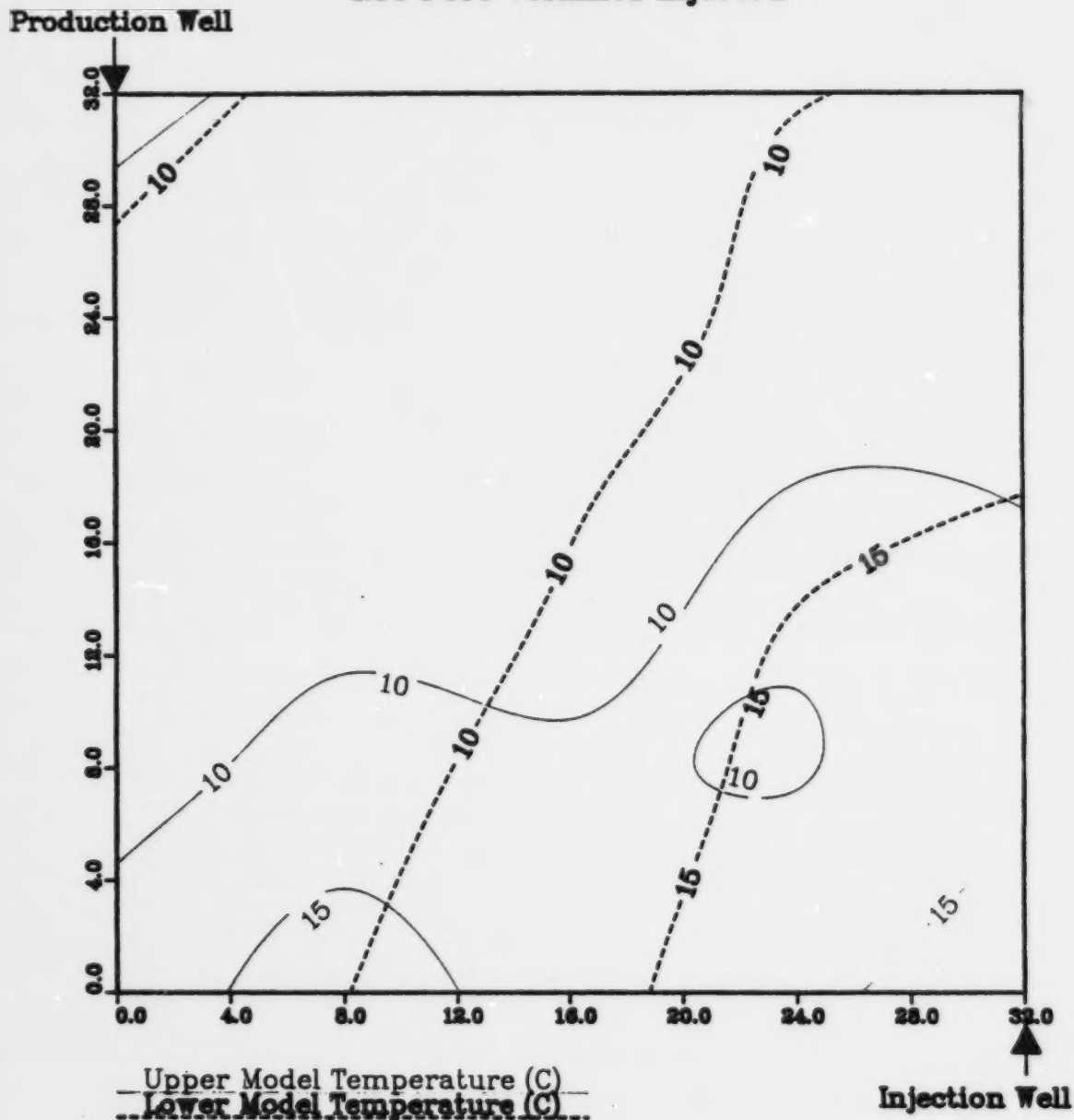


Figure A.278 : Run 48B
Solvent-Steamflood After a Waterflood

Temperature Profile for
2.00 Pore Volumes Injected

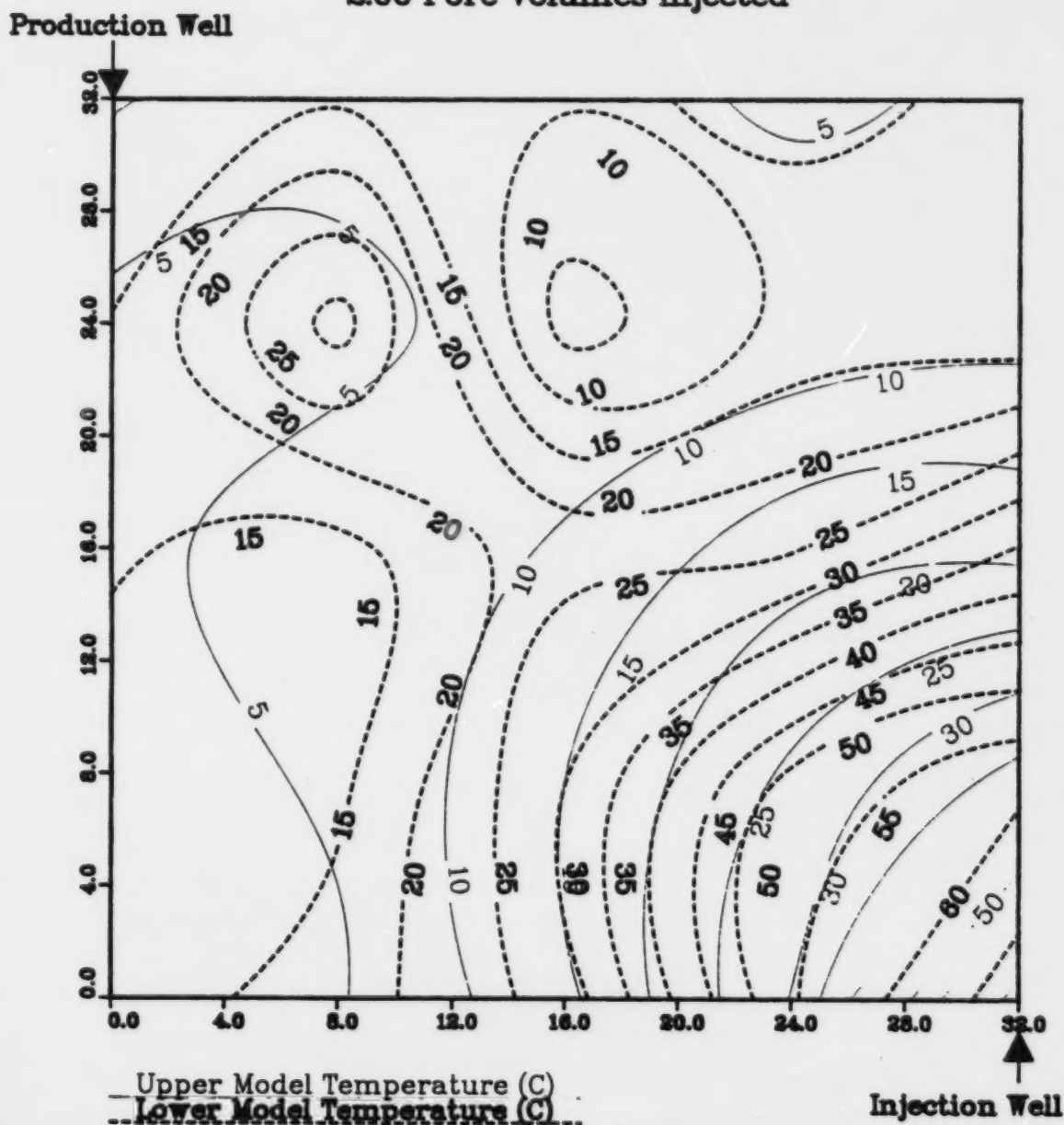


Figure A279 : Run 48B
Solvent-Steamflood After a Waterflood

Temperature Profile for
2.50 Pore Volumes Injected

Production Well

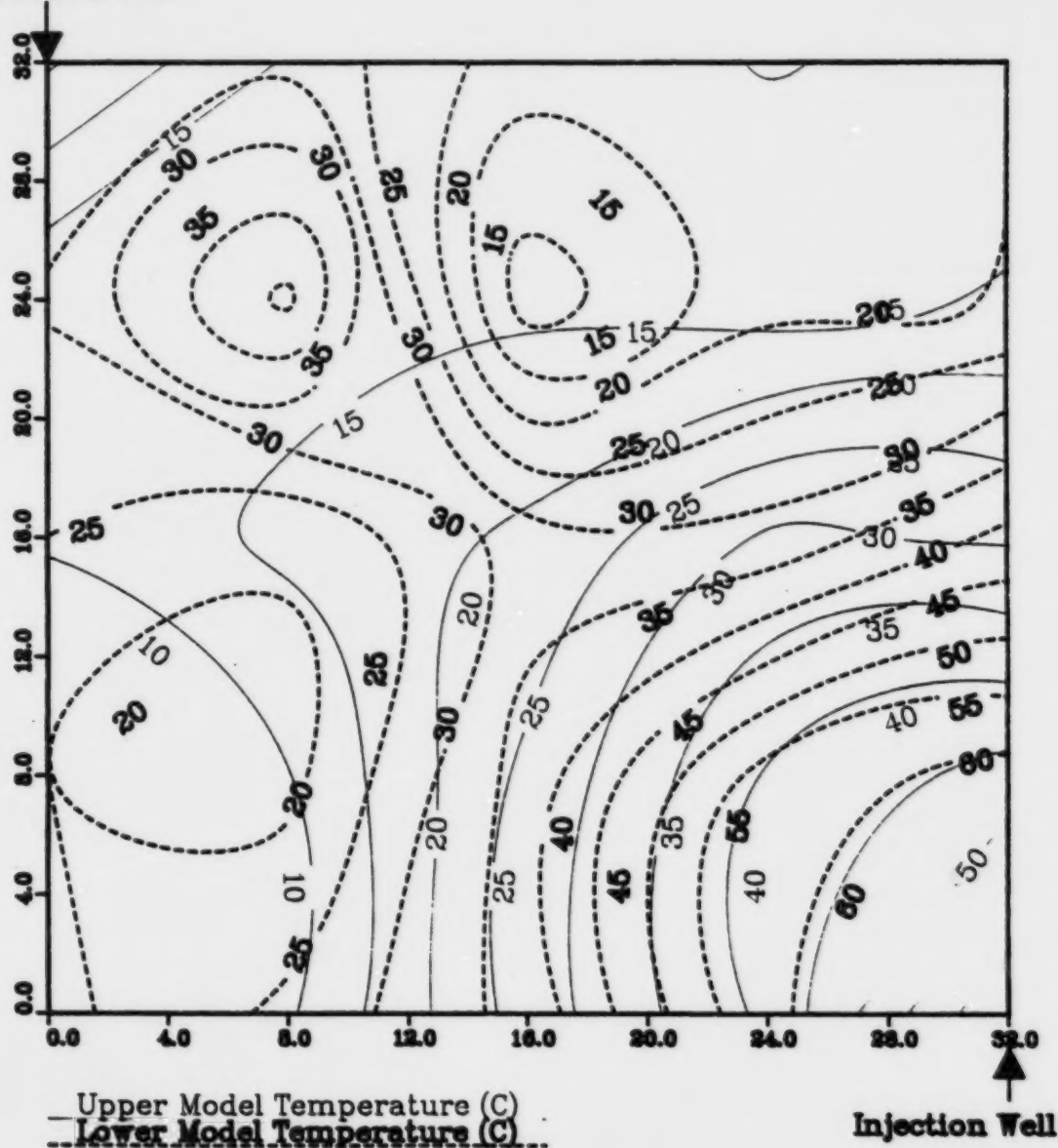
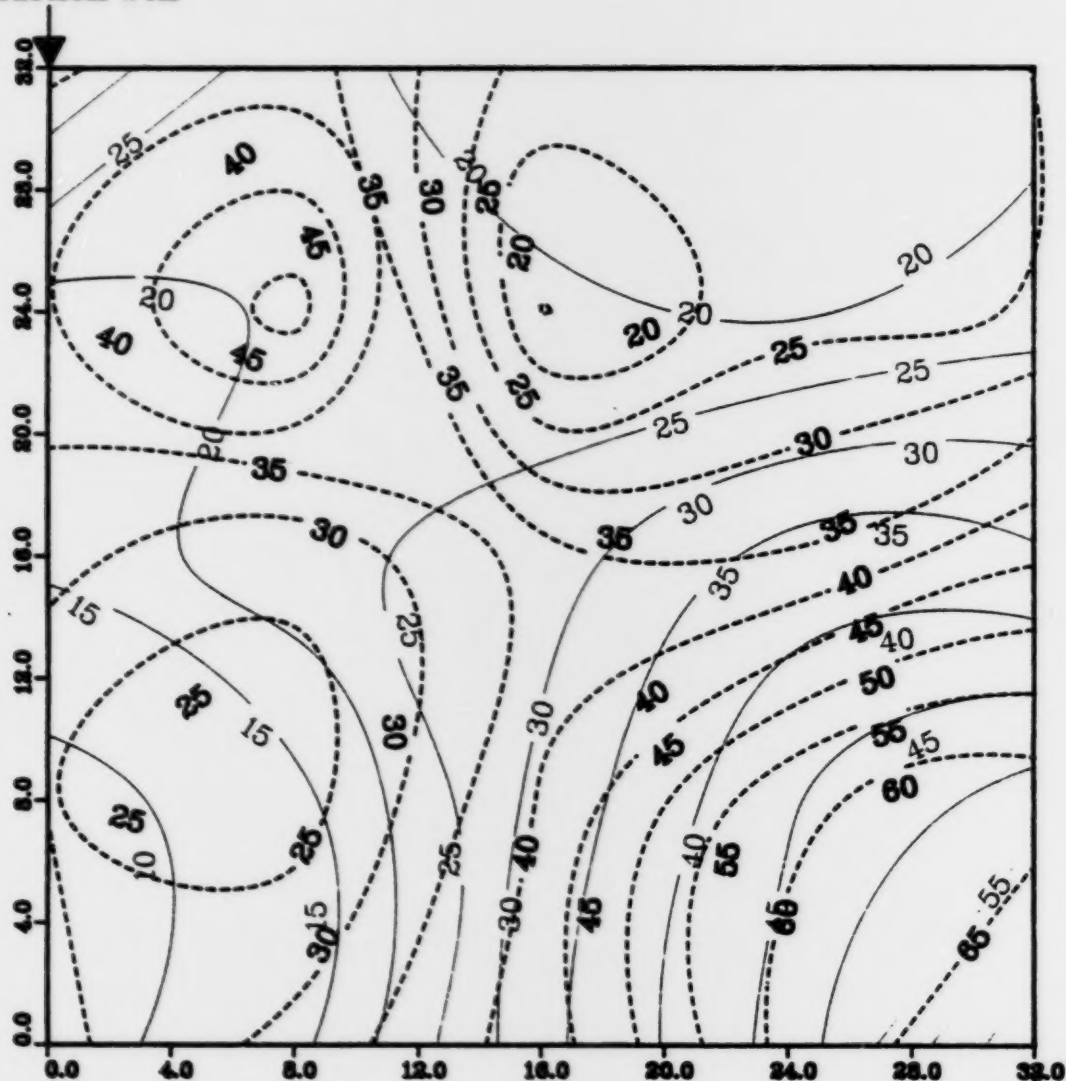


Figure A.280 : Run 48B
Solvent-Steamflood After a Waterflood

Temperature Profile for
3.00 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

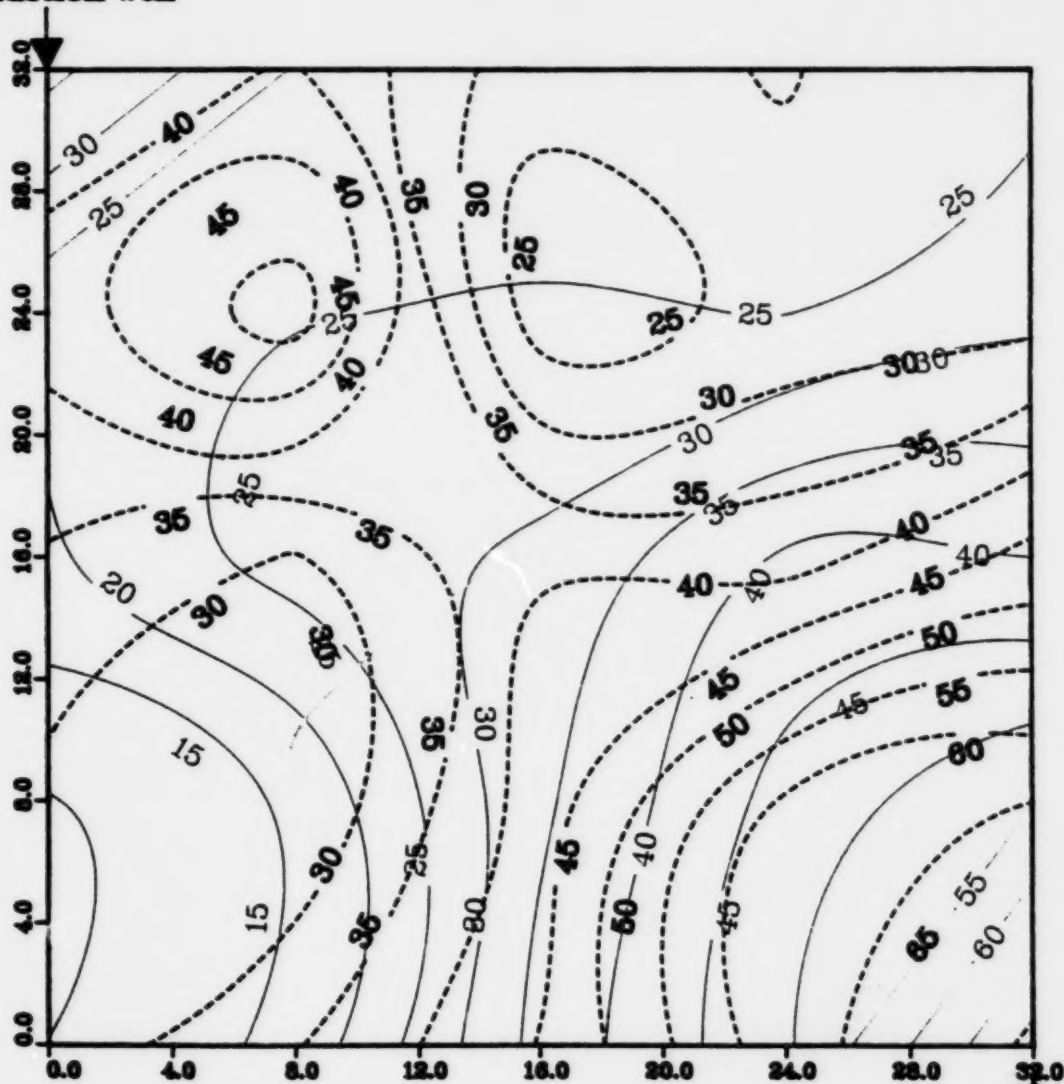
Lower Model Temperature (C)

Injection Well

Figure A281 : Run 48B
Solvent-Steamflood After a Waterflood

Temperature Profile for
3.50 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

Lower Model Temperature (C)

Injection Well

**Figure A.282 :Run 48 Temp Profile
Injector to Producer Cross-Section
2.00 Pore Volumes Injected.**

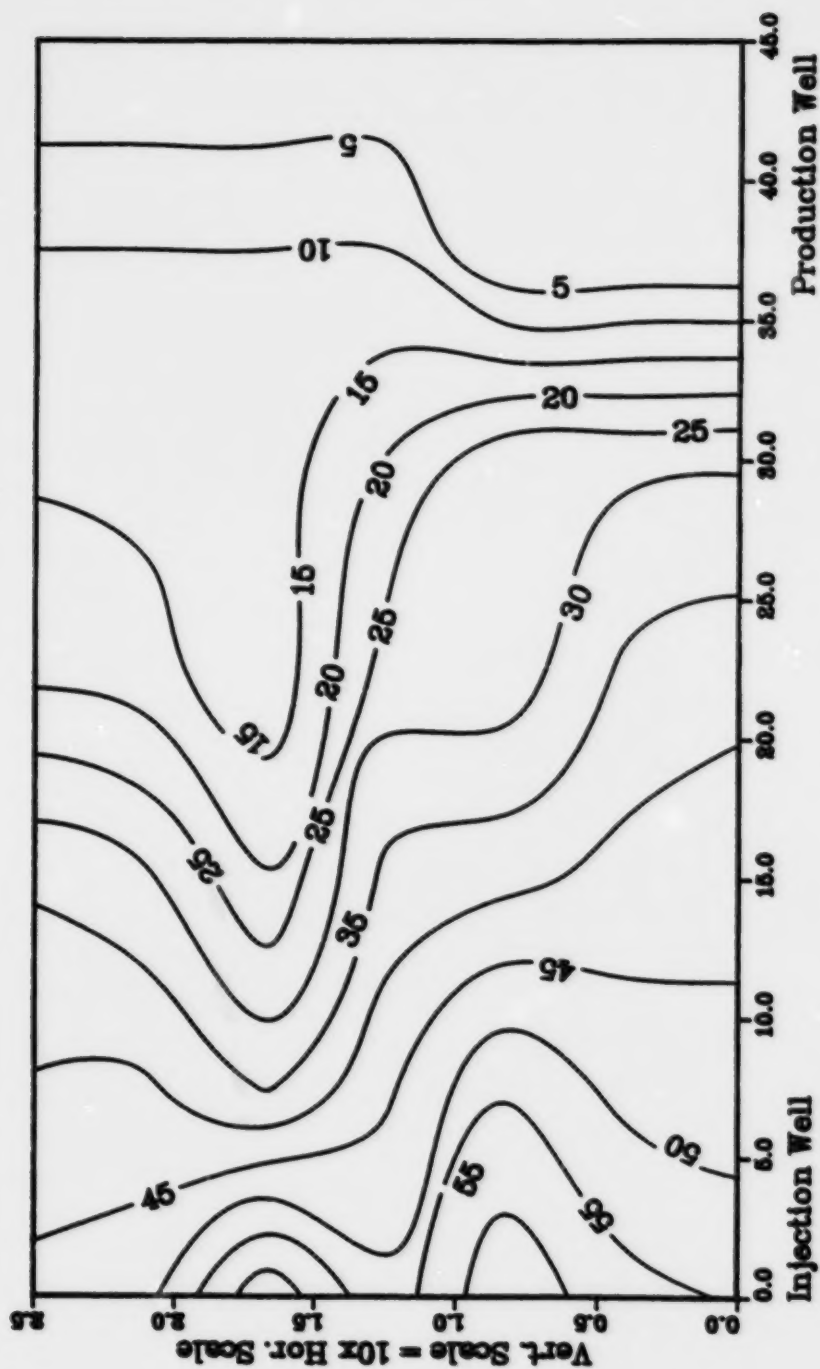


**Figure A.283 : Run 48 Temp Profile
Injector to Producer Cross-Section
2.50 Pore Volumes Injected.**

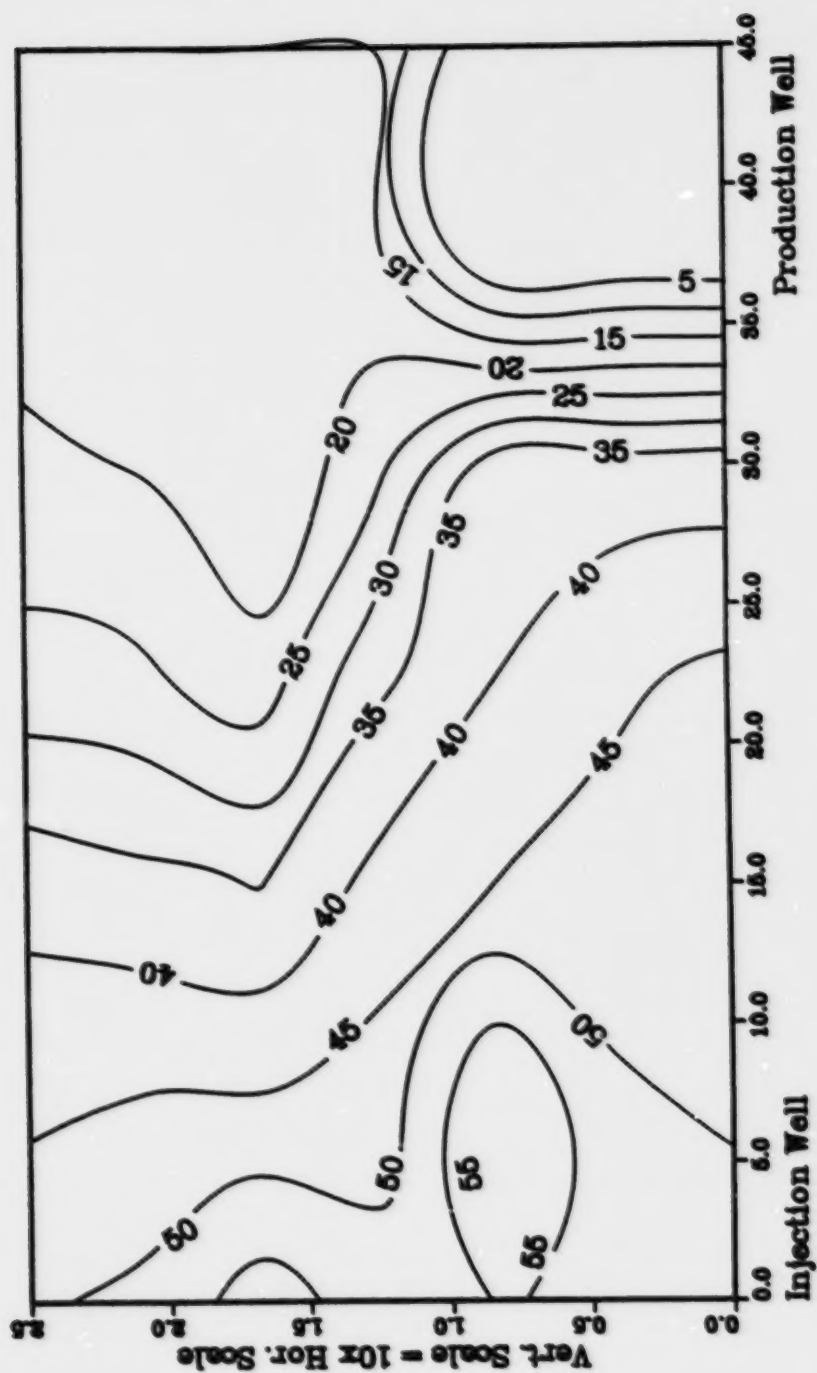


**Figure A.284 :Run 48 Temp Profile
Injector to Producer Cross-Section
3.00 Pore Volumes Injected.**

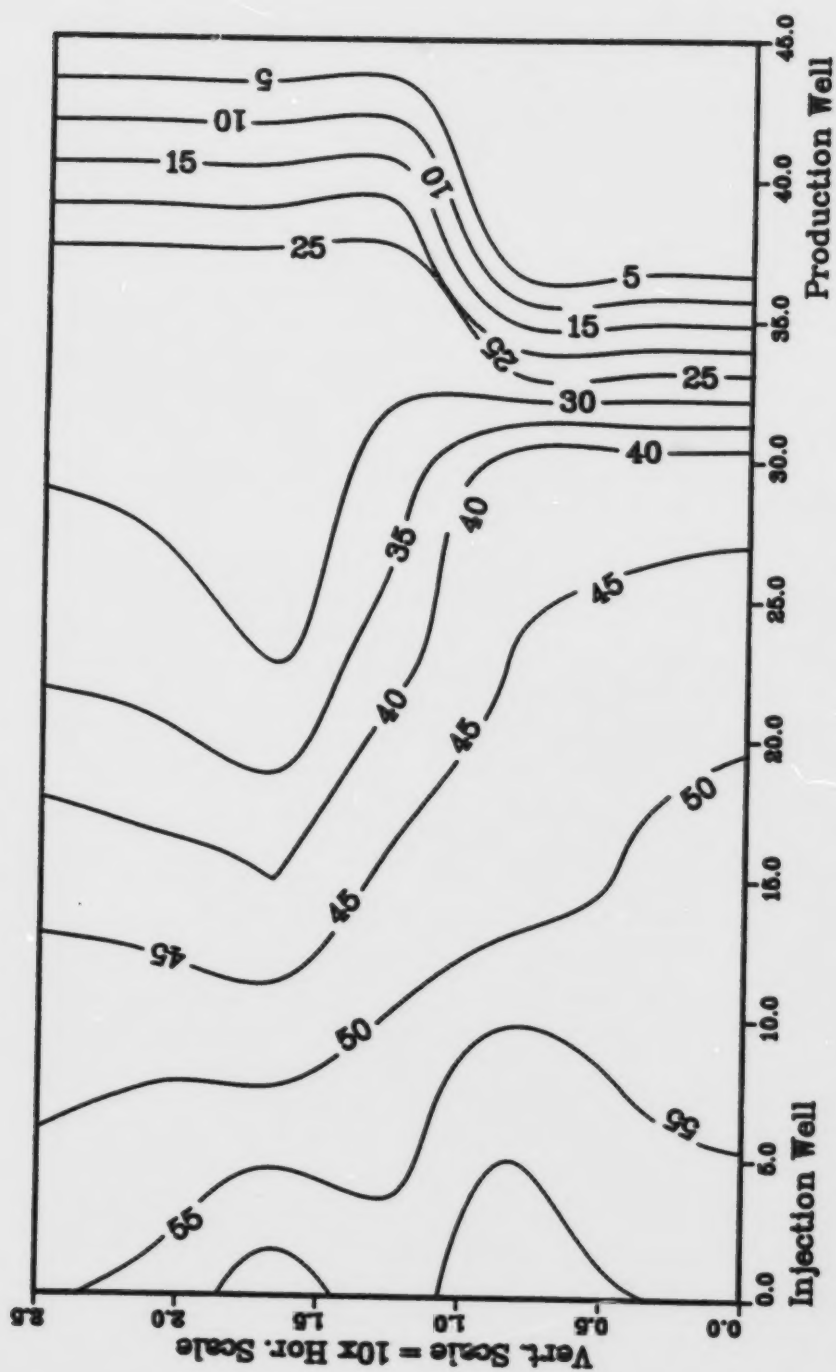


**Figure A.285 :Run 48 Temp Profile
Injector to Producer Cross-Section
3.50 Pore Volumes Injected.**

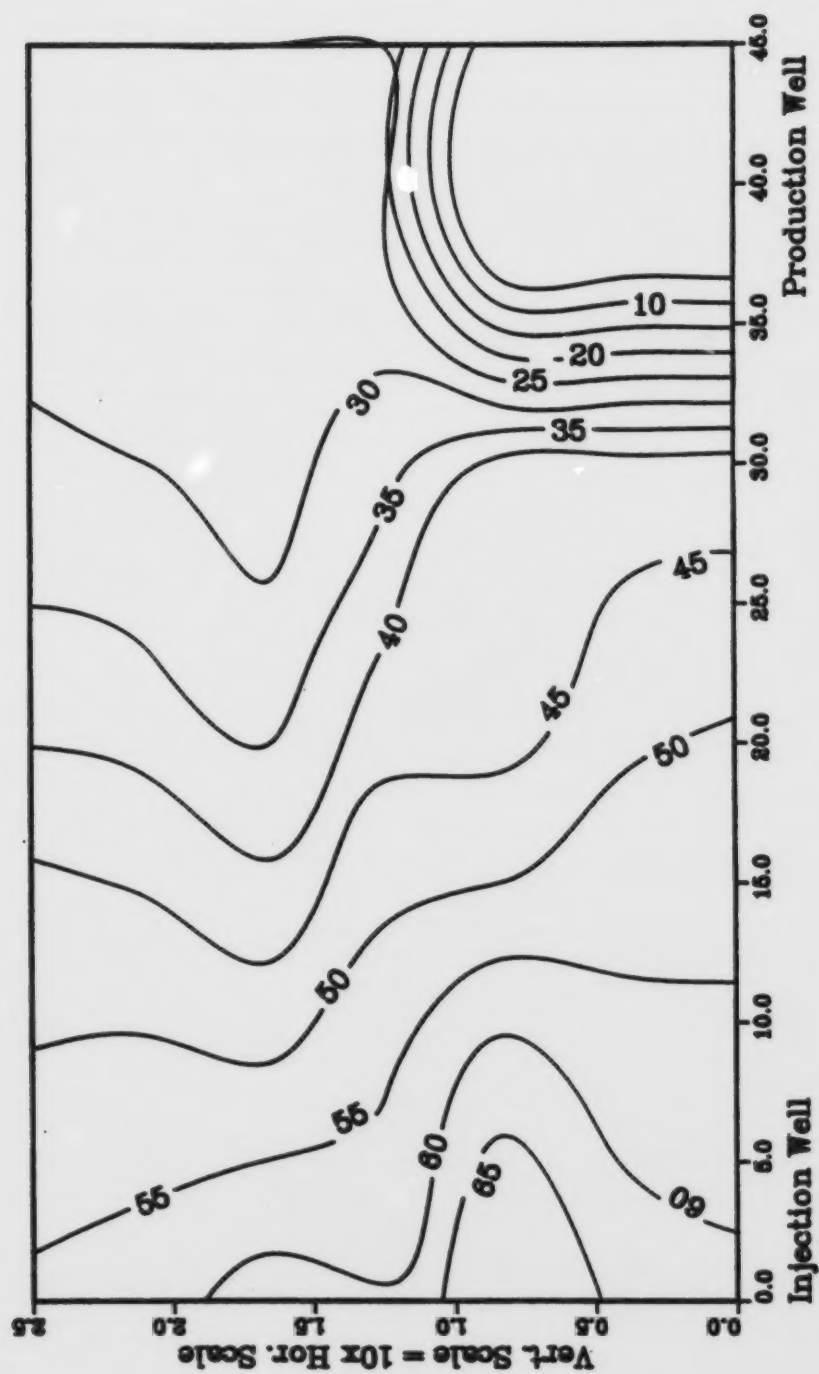


Figure A.286 : Run 26
Steamflood of Homogeneous Model

Temperature Profile for
0.25 Pore Volumes Injected

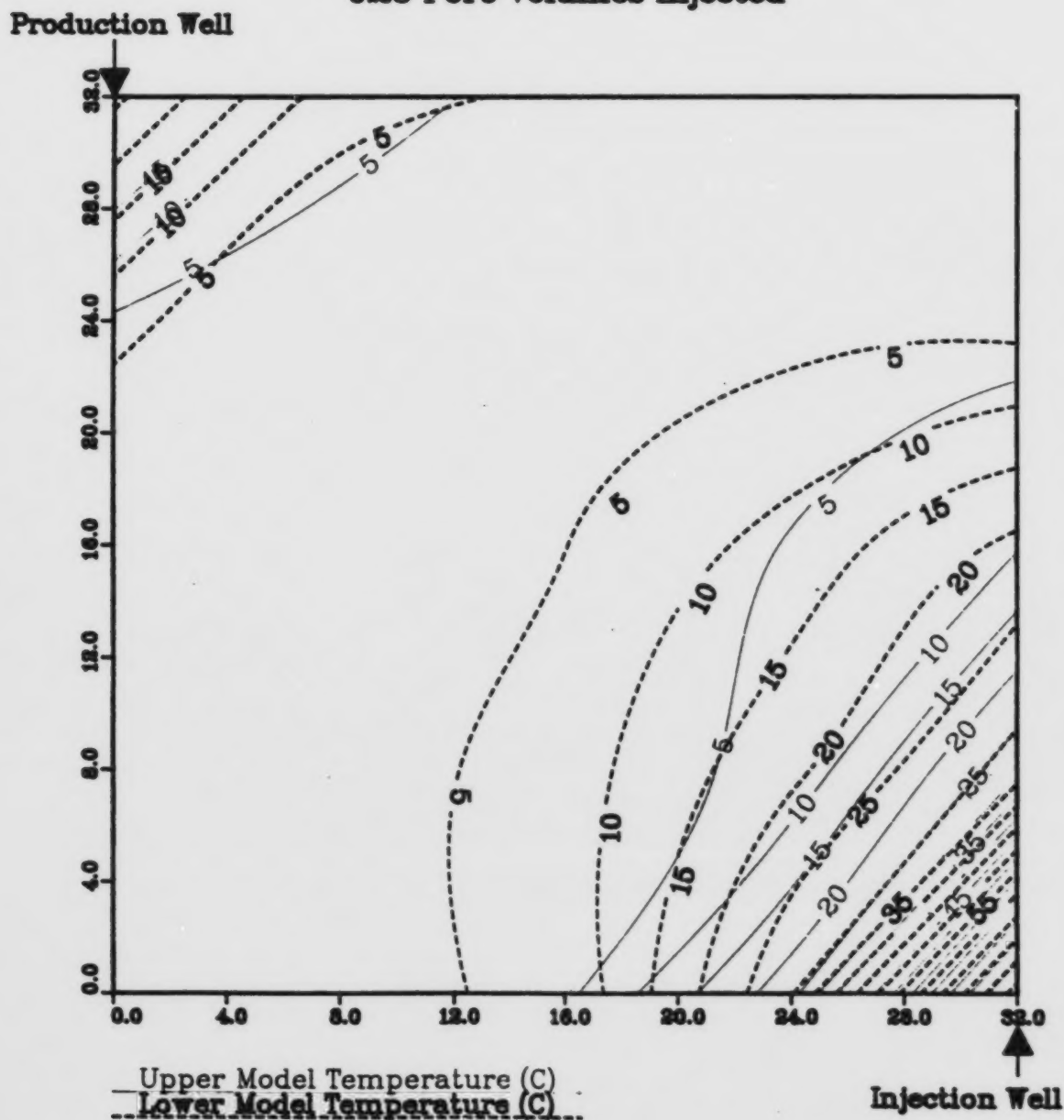


Figure A287 : Run 26
 Steamflood of Homogeneous Model

Temperature Profile for
 0.50 Pore Volumes Injected

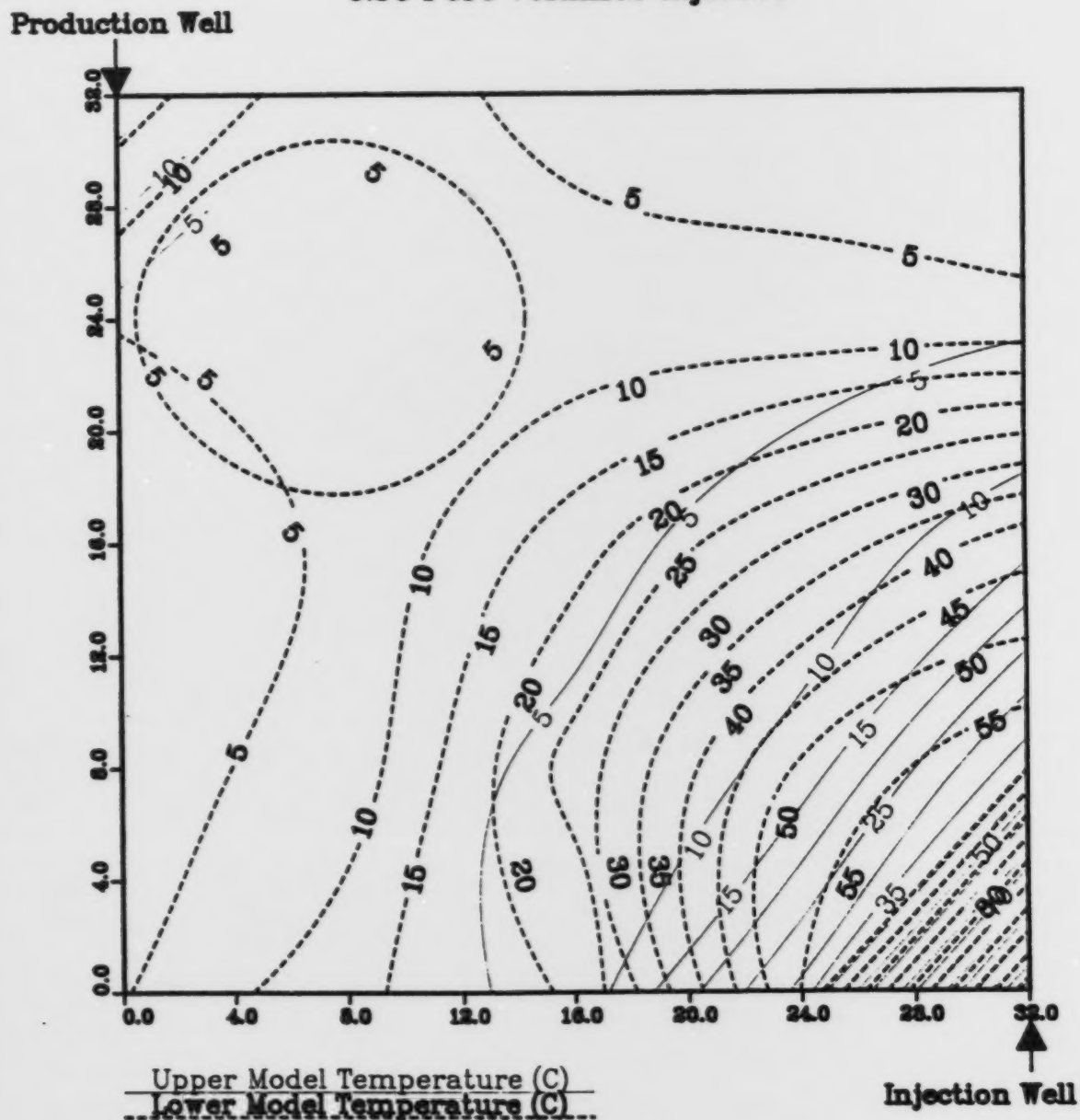


Figure A.288 : Run 26
Steamflood of Homogeneous Model

Temperature Profile for
0.75 Pore Volumes Injected

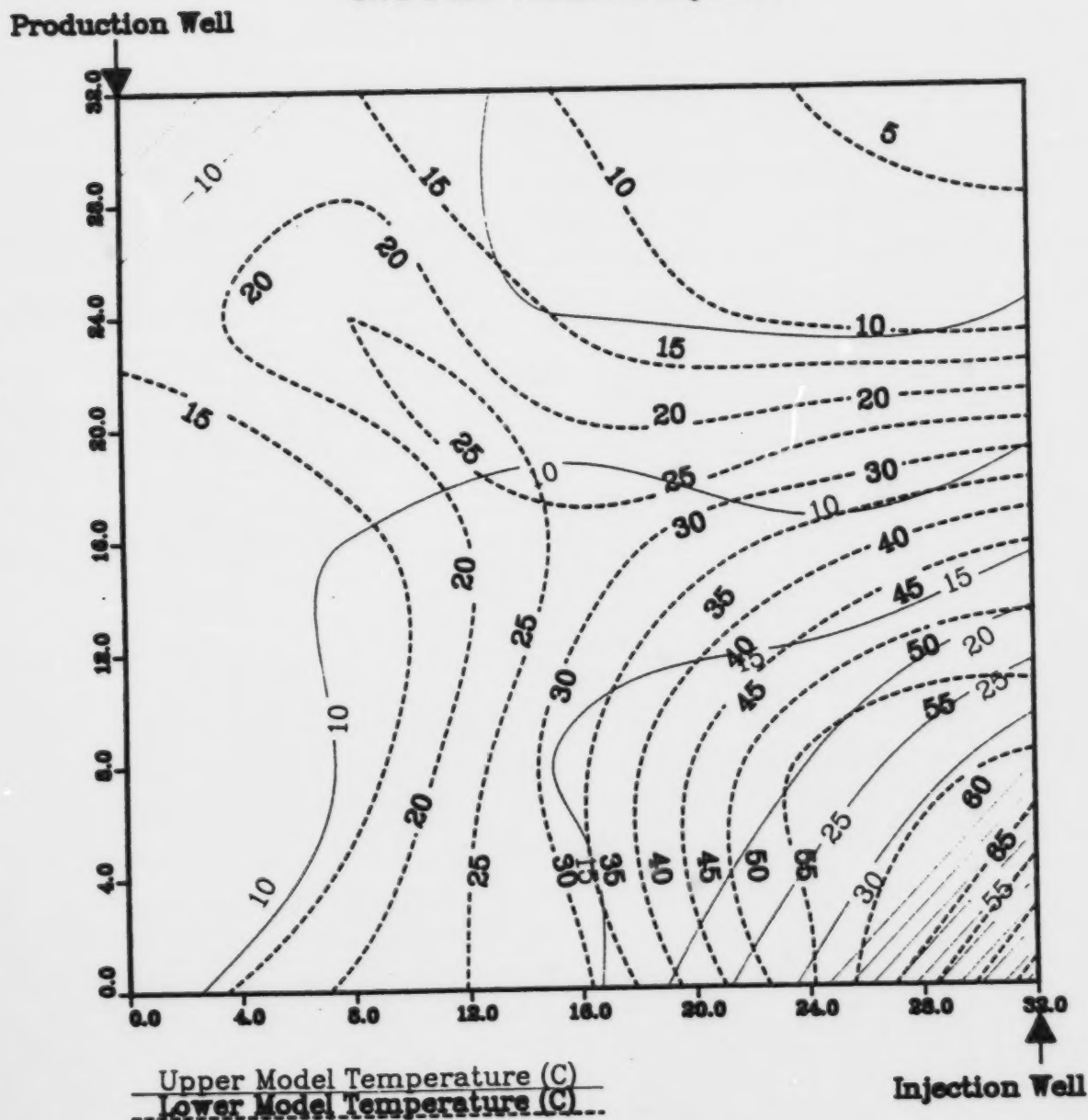


Figure A289 : Run 26
 Steamflood of Homogeneous Model

Temperature Profile for
 1.00 Pore Volumes Injected

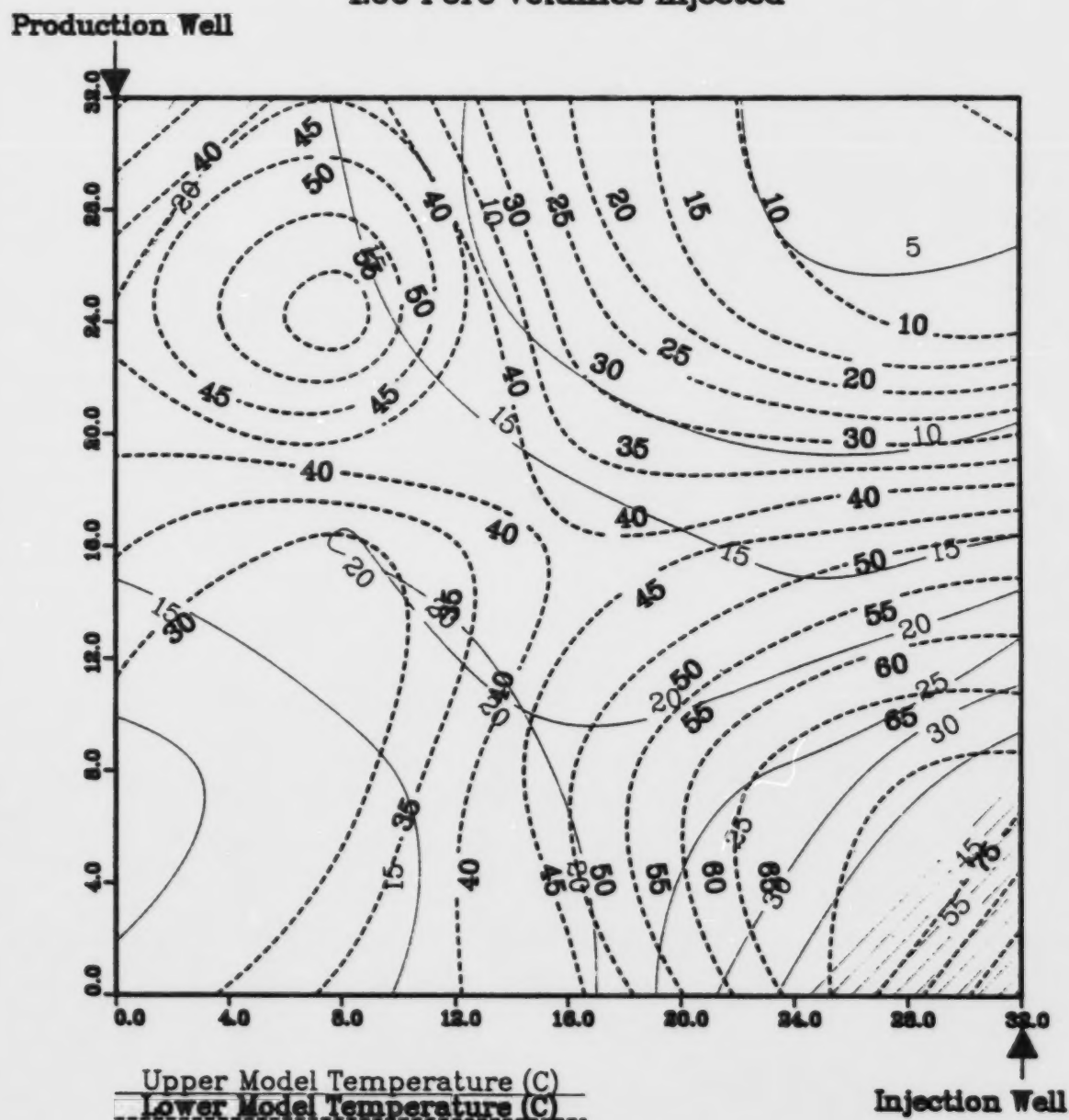
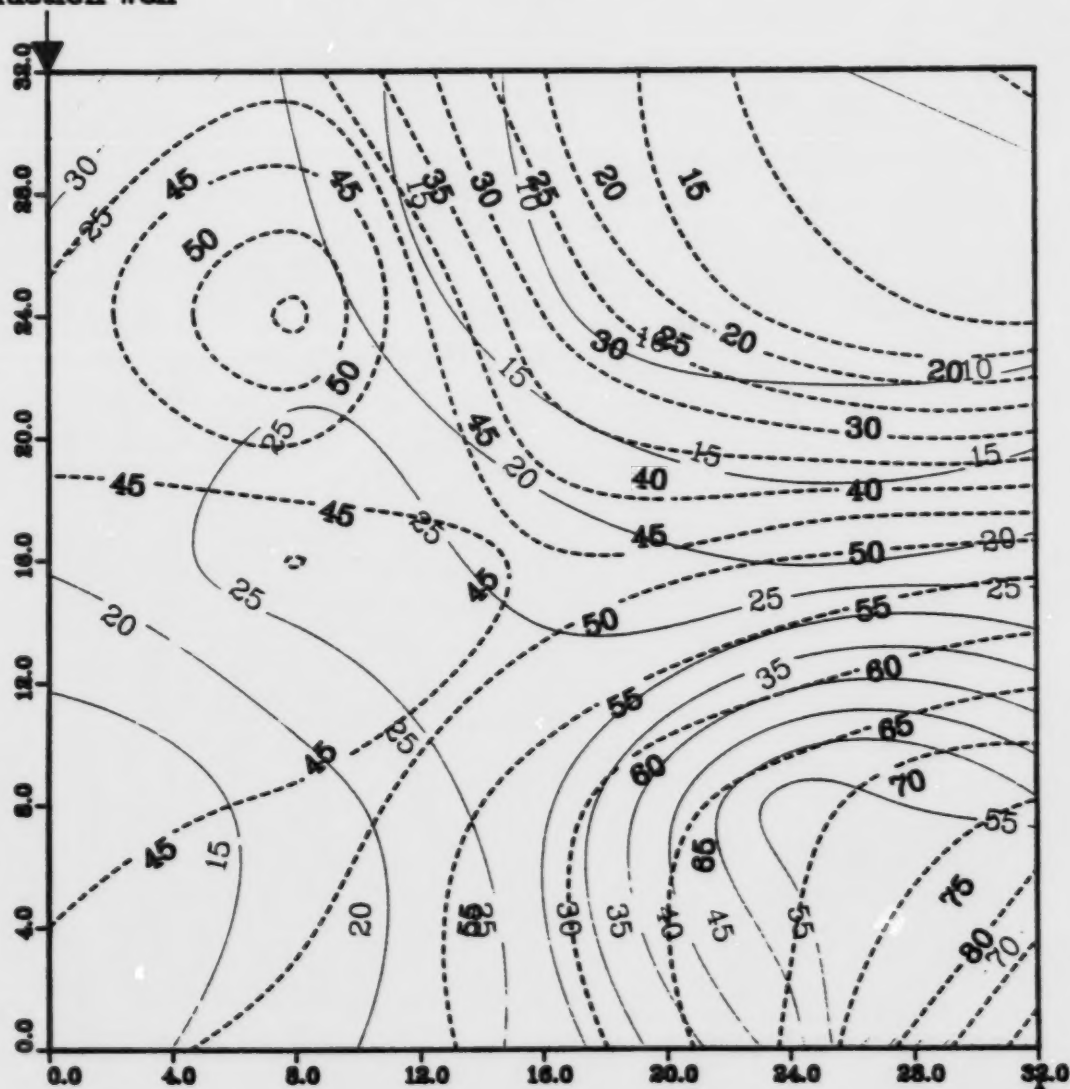


Figure A.290 : Run 26
Steamflood of Homogeneous Model

Temperature Profile for
1.25 Pore Volumes Injected

Production Well



Upper Model Temperature (C)

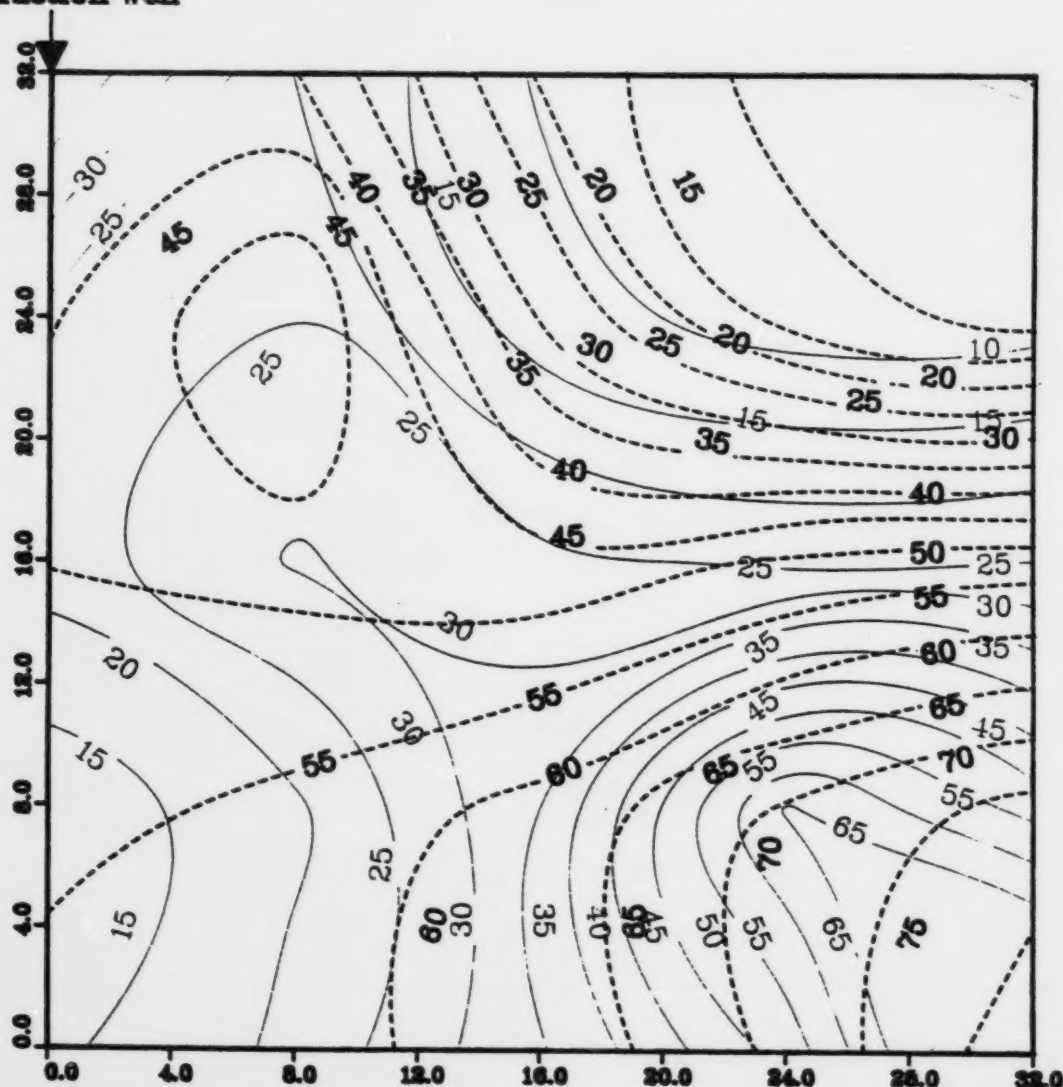
Lower Model Temperature (C)

Injection Well

Figure A.291 : Run 26
Steamflood of Homogeneous Model

Temperature Profile for
150 Pore Volumes Injected

Production Well



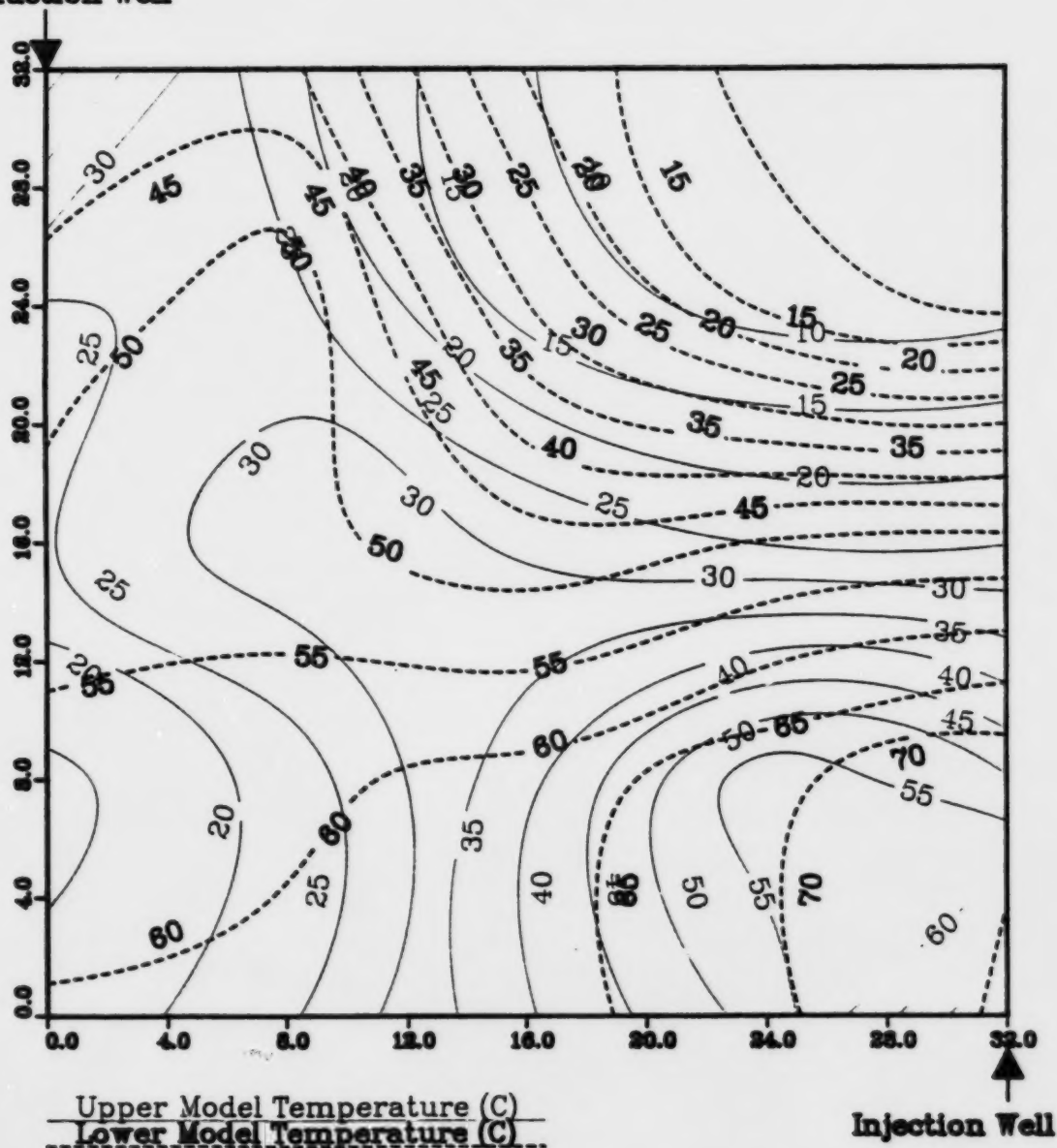
Upper Model Temperature (C)
Lower Model Temperature (C)

Injection Well

Figure A292 : Run 26
Steamflood of Homogeneous Model

Temperature Profile for
1.75 Pore Volumes Injected

Production Well



Appendix B

Computer Programs Used in Heat Flow Analysis


```

C.....
C
C   The Lauwerier equation was developed to predict
C   formation heating due to Hot Water Injection.
C   (Sensible Heat Only)
C
C   This program utilizes the Lauwerier equation and
C   the temperature contour profiles for Experiment 26
C   (0.25 to 1.00 Pore Volumes). The area covered by each
C   corresponding temperature on each profile was measured
C   by a planimeter and then substituted into the Lauwerier
C   equation in order to obtain a estimated temperature
C   related to this measured area.
C
C   The contour temperature and the temperature value
C   obtained from the Lauwerier equation are then compared
C   to determine if experiment 26 more closely represents hot
C   water injection instead of the desired continuous
C   steamflood.
C.....
C
C   REAL DOIL,COIL,MOIL,DH2O,CH2O,MH2O,KHG,MG,KHOB,MOB,TM,HT,
C   @IW,AREA,TR,TF,XD,TD,TEMP,MS,POR,SOIL,SH2O
C
C   WRITE(6,33)
33  FORMAT(5X,'ACTUAL TEMP C',5X,'LAUWERIER TEMP C'//)
C
C   Density of Oil (lb/ft3)
C   DOIL=38.375
C   Specific Heat of Oil (Btu/lb-F)
C   COIL=0.5162
C   Heat Capacity of Oil (Btu/ft3-F)
C   MOIL=DOIL*COIL
C   Density of Water (lb/ft3)
C   DH2O=61.186
C   Specific Heat of Water (Btu/lb-F)
C   CH2O=0.9996
C   Heat Capacity of Water (Btu/ft3-F)
C   MH2O=DH2O*CH2O
C   Thermal Conductivity of Glass (Btu/hr-ft-F)
C   KHG=0.5
C   Heat Capacity of Glass (Btu/ft3-F)
C   MG=25.9
C   Thermal Conductivity of Overburden (Btu/hr-ft-F)
C   KHOB=1.46426
C   Heat Capacity of Overburden (Btu/ft3-F)
C   MOB=28.8558
C   Thickness (Feet)
C   HT=.104167
C   Injection Rate of Fluid (BB1/Day)
C   IW=1.3405
C   Temperature of Reservoir (F)
C   TR=37.4
C   Temperature of Fluid (F)
C   TF=154.71
C   Porosity of Model
C   POR=.3346
C   Oil Saturation
C   READ(5,*)J,PV,SOIL

```

```

C      Water Saturation
SH20=1-SOIL
C      Time(hours)
TM=PV*14055./((226.8*60.))
C      Heat Capacity of Saturated Porous Medium (Btu/ft3-F)
MS=POR*SOIL*MOIL+POR*SH20*MH20+(1.0-POR)*MG
C
C      Dimensionless Time
TD=4.0*KHOB*MOB*TM/((MS**2)*(HT**2))
C
C      Read Contour Temperature and Corresponding Area
C      From Data File
DO 100 I=1,J
READ(5,*)TEMP,AREA
C
C
C      Dimensionless Distance
R1=4.*24.*KHOB*MOB*AREA
R2=5.615*MS*DH20*CH20*IW*HT
XD=R1/R2
C
C      Limits For Lauwerier Equation are Applied
C
IF(TD-XD) 1,1,2
C
C      If xD is greater than or equal to tD then Lauwerier
C      temperature is equal initial reservoir temperature.
C      (37.4 F)
C
1      WRITE(6,10)
10     FORMAT (10X,'xD is greater than or equal to tD')
      TLAU=3.0
      GO TO 9
C
C      If xD is less than tD then Lauwerier equation can
C      be used
C
2      R3=(TF-TR)*ERFC(XD/(2*SQRT(TD-XD)))
      TLAU=((TR+R3)-32.0)/1.8
C
C      The Contour Temperature and Lauwerier Temperature are
C      written into the output file so these two values can be
C      compared to see how closely experiment 26 represents a
C      hot waterflood.
C
9      WRITE(6,20)TEMP,TLAU
20     FORMAT(12X,F5.2,15X,F5.2)
100    CONTINUE
      STOP
      END

```

```

C .....
C   This program calculates the Steam Zone Volume for every
C   0.25 pore volumes of steam injected for Experiment 26 using
C   the Marx-Langenheim Model for Formation Heating by Steam
C   Injection.
C
C   Marx-Langenheim assumes that the latent heat injection
C   rate is greater than the rate of its consumption.
C
C .....
C   REAL DOIL,COIL,MOIL,DH2O,CH2OT,MH2O,KHG,MG,KHOB,MOB,TM,HT,
C   @IW,TR,TF,XD,TD,MS,POR,SOIL,SH2O,FST,QI,LV,F1,VS,SST,PV,CH2O
C
C   Quality of Steam
C   FST=0.08324
C   Latent Heat of Vaporization (Btu/lb)
C   LV=1017.755
C   Density of Oil (lb/ft3)
C   DOIL=38.375
C   Specific Heat of Oil (Btu/lb-F)
C   COIL=0.5162
C   Heat Capacity of Oil (Btu/ft3-F)
C   MOIL=DOIL*COIL
C   Density of Water (lb/ft3)
C   DH2O=61.186
C   Specific Heat of Water (Btu/lb-F)
C   CH2O=1.01495
C   hw-hr (Btu/lb)
C   CH2OT=101.23
C   Heat Capacity of Water (Btu/ft3-F)
C   MH2O=DH2O*CH2O
C   Thermal Conductivity of Glass (Btu/hr-ft-F)
C   KHG=0.5
C   Heat Capacity of Glass (Btu/ft3-F)
C   MG=25.9
C   Thermal Conductivity of Overburden (Btu/hr-ft-F)
C   KHOB=1.46426
C   Heat Capacity of Overburden (Btu/ft3-F)
C   MOB=28.8558
C   Thickness (Feet)
C   HT=.104167*2.0
C   Injection Rate of Fluid (BB1/Day)
C   IW=2.054
C   Temperature of Reservoir (F)
C   TR=37.4
C   Temperature of Fluid (F)
C   TF=154.71
C   POROSITY OF MODEL
C   POR=.3346
C
C   DO 100 I=1,8
C   Fraction of Pore Volume Injected into the Model
C   PV=0.25*I
C   Calculate Time Using the Pore Volume Injected (hrs)
C   TM=PV*14055./(226.8*60)
C   Oil Saturation
C   SOIL=0.15

```

```

C      Steam Saturation
SST=0.50
C      Water Saturation
SH20=1-SOIL-SST
MS=POR*SOIL*MOIL+POR*SH20*MH20+(1.0-POR)*MG
C
C      Dimensionless Time
TD=4.0*KHOB*MOB*TM/((MS**2)*(HT**2))
WRITE(6,22)PV
22  FORMAT(/10X,F4.2,' Pore Volumes Injected')
C
C
C      Calculate Heat Injection Rate (Btu/hr)
QI=350.*IW*(CH20T+F5T*LV)/24.
C
C      F1=EXP(TD)*ERFC(SQRT(TD))+2.*SQRT(TD/3.141592)-1.
R1=QI*MS*(HT**2.0)*F1
R2=4.*KHOB*MOB*(TF-TR)
C
C      Steam Zone Volume as a Percentage of
C      Total Model Bulk Volume
C
VS=(R1/R2)/1.481481*100
WRITE(6,20)VS
20  FORMAT(10X,'Vs is ',F5.2,2X,'% of Models Bulk Volume')
100 CONTINUE
STOP
END

```

```

C.....
C   This program calculates the Steam Zone Volume for every
C   0.25 pore volumes of steam injected in Experiment 26
C   using the Mandl-Volek Model of Formation Heating by
C   Steam Injection.
C
C   The Mandl-Volek Model allows for the convective heat
C   transport by hot water ahead of the condensation front.
C
C.....
C   REAL DOIL,COIL,MOIL,DH2O,CH2OT,MH2O,KHG,MG,KHOB,MOB,TM,HT,
C   *IW,TR,TF,XD,TD,MS,POR,SOIL,SH2O,FST,QI,LV,F1,VS,SST,PV,CH2O
C   *TC,TCG
C   INTEGER A
C
C   Quality of Steam
C   FST=0.08324
C   Latent Heat of Vaporization (Btu/lb)
C   LV=1017.755
C   Density of Oil (lb/ft3)
C   DOIL=38.375
C   Specific Heat of Oil (Btu/lb-F)
C   COIL=0.5162
C   Heat Capacity of Oil (Btu/ft3-F)
C   MOIL=DOIL*COIL
C   Density of Water (lb/ft3)
C   DH2O=61.186
C   Specific Heat of Water (Btu/lb-F)
C   CH2O=1.01495
C   hw-hr (Btu/lb)
C   CH2OT=101.297
C   Heat Capacity of Water (Btu/ft3-F)
C   MH2O=DH2O*CH2O
C   Thermal Conductivity of Glass (Btu/hr-ft-F)
C   KHG=0.5
C   Heat Capacity of Glass (Btu/ft3-F)
C   MG=25.9
C   Thermal Conductivity of Overburden (Btu/hr-ft-F)
C   KHOB=1.46426
C   Heat Capacity of Overburden (Btu/ft3-F)
C   MOB=28.8558
C   Thickness (Feet)
C   HT=.104167*2.0
C   Injection Rate of Fluid (BB1/Day)
C   IW=2.054
C   Temperature of Reservoir (F)
C   TR=37.4
C   Temperature of Fluid (F)
C   TF=154.71
C   POROSITY OF MODEL
C   POR=.3346
C   Oil Saturation
C   SOIL=0.15
C   Steam Saturation
C   SST=0.50
C   Water Saturation
C   SH2O=1-SOIL-SST
C   Heat Capacity of Saturated Reservoir

```

```

C      MS=POR*SOIL*MOIL+POR*SH2O*MH2O+(1.0-POR)*MG
C      Dimensionless Critical Time (From Table 5.1 of SMFA Text)
C      TDC=0.4726
C      Critical Time (Hours)
C      TC=MS**2.*HT**2.*TDC/(4.*KHOB*MOB)
C
C
C      DO 100 I=1,8
C      Fraction of Pore Volume Injected into the Model
C      PV=0.25*I
C      Calculate Time Using the Pore Volume Injected (hrs)
C      TM=PV*14055./((226.8*60)
C
C      Dimensionless Time
C      TD=4.0*KHOB*MOB*TM/((MS**2)*(HT**2))
C
C      Check if time is past critical time and then
C      Mandl-Volek equation applies otherwise Marx-Langenheim
C      is used.
C
C      IF(TM-TC)1,1,2
C      Marx-Langenheim
C      1 F1=EXP(TD)*ERFC(SQRT(TD))+2.*SQRT(TD/3.141592)-1.
C      A=1
C      GO TO 3
C      Mandl-Volek
C      2 X1=EXP(TD)*ERFC(SQRT(TD))+2.*SQRT(TD/3.141592)-1.
C      X2=(1/(1+(FST*LV/CH2OT)))-(TD-TDC)/(3.*SQRT(3.141592*TD))
C      X3=((TD-TDC-3.)/3.)*EXP(TD)*ERFC(SQRT(TD))
C      X4=SQRT((TD-TDC)/3.141592)
C      F1=X1-X4*(X2+X3)
C      A=2
C      3 WRITE(6,22)PV
C      22 FORMAT(/10X,F4.2,' Pore Volumes Injected')
C
C      Heat Injection Rate(Btu/hr)
C      QI=350.*IW*(CH2OT+FST*LV)/24.
C
C      R1=QI*MS*(HT**2.0)*F1
C      R2=4.*KHOB*MOB*(TF-TR)
C
C      Steam Zone Volume as a Percentage of
C      the Model's Bulk Volume (1.481481 ft3)
C      VS=(R1/R2)/1.481481*100.
C
C
C      WRITE(6,20)VS
C      20 FORMAT(10X,'Vs is ',F5.2X,'% of Models Bulk Volume')
C      100 CONTINUE
C      STOP
C      END

```

```

C.....
C      This program calculates the total heat injected into the
C      model, the amount of heat contained in the model and the
C      amount of heat lost from the model in Experiment 26 which
C      was a base steamflood.
C
C      After planimentering all of the Run 26 temperature profiles
C      one could then use this program to calculate the above
C      mentioned values for Experiment 26.
C
C      In general this program does a simple heat balance on the
C      model during Experiment 26. Where the heat in the model
C      is determined by summing heat contained in each
C      temperature's incremental volume which is calculated by:
C
C      Heat=Ms*Vol. for partial temp.*Change in temp.
C
C      The total heat in the model is obtained by the summation
C      of these Volumes.
C.....
C      REAL DOIL,COIL,MOIL,DH2O,CH2OT,MH2O,KHG,MG,KHOB,MOB,TM,HT,
C      *IW,TR,MS,POR,SOIL,SH2O,FST,OI,LV,SST,PV,CH2O,
C      *AREA1,AREA2,VTEMP1,VTEMP2,QM,QM1,QM2,TOTALQ,LOSTQ
C      INTEGER A
C
C      Quality of Steam
C      FST=0.08324
C      Latent Heat of Vaporization (Btu/lb)
C      LV=1017.755
C      Density of Oil (lb/ft3)
C      DOIL=38.375
C      Specific Heat of Oil (Btu/lb-F)
C      COIL=0.5162
C      Heat Capacity of Oil (Btu/ft3-F)
C      MOIL=DOIL*COIL
C      Density of Water (lb/ft3)
C      DH2O=61.186
C      Specific Heat of Water (Btu/lb-F)
C      CH2O=1.01495
C      hw-hr (Btu/lb)
C      CH2OT=101.297
C      Heat Capacity of Water (Btu/ft3-F)
C      MH2O=DH2O*CH2O
C      Thermal Conductivity of Glass (Btu/hr-ft-F)
C      KHG=0.5
C      Heat Capacity of Glass (Btu/lb-F)
C      MG=25.9
C      Thermal Conductivity of Overburden (Btu/hr-ft-F)
C      KHOB=1.46426
C      Heat Capacity of Overburden (Btu/ft3-F)
C      MOB=28.8558
C      Thickness (Feet)
C      HT=.104167
C      Injection Rate of Fluid (BB1/Day)
C      IW=2.054
C
C      Since the lowest temperature on the contours is
C      5.0 C (41.0 F) then this is assumed as the initial

```



```

C      reservoir temperature.
C
C      Temperature of Reservoir (F)
C      TR=41.0
C      POROSITY OF MODEL
C      POR=.3346
C      Calculate Heat Injection Rate (Btu/hr)
C      QI=350.*IW*(CH2OT+FST*LV)/24.
C
C
C      DO 10 I=1,7
C          READ (5,*)PV,SOIL
C          QM=0.0
C          QM1=0.0
C          QM2=0.0
C          LOSTQ=0.0
C          TOTALQ=0.0
C          Time (hours)
C          TM=PV*14055./(226.8*60.)
C          Water Saturation (fraction)
C          SH2O=1.-SOIL
C          NS=POR*SOIL*MOIL+POR*SH2O*MH2O+(1.0-POR)*MG
C
C      Calculate Total Amount of Heat Injected (Btu)
C      TOTALQ=QI*TM
C
C      DO 20 J=1,13
C
C          Reads Temperature and its corresponding areal extent
C          in the upper and lower portion of the model, respectively.
C
C          READ(5,*)TEMP,AREA1,AREA2
C          Convert Temperature to Fahrenheit
C          TEMP=TEMP*1.8+32.
C          Upper Portion
C          Volume in Upper Portion of Model Corresponding to
C          the Temperature is Calculated
C
C          VTEMP1=AREA1*2.9941052*HT
C
C          Heat contained in this volume is calculated and summed
C          up for the entire upper portion of the model.
C
C          QM1=QM1+(NS*VTEMP1*(TEMP-TR))
C          Lower Portion
C          Same procedure as was performed for the upper portion
C          of the model is carried out for the lower portion.
C
C          VTEMP2=AREA2*2.9941052*HT
C          QM2=QM2+(NS*VTEMP2*(TEMP-TR))
C
C      20      CONTINUE
C
C
C
C          Heat Remaining in the Model
C          QM=QM1+QM2
C          Heat Lost to Surroundings is Calculated
C          LOSTQ=TOTALQ-QM

```

```
C
C      Percentage of Heat Remaining in the Model
      QM=QM/TOTALQ*100.
C      Percentage of Heat Lost from the Model
      LOSTQ=LOSTQ/TOTALQ*100.
C
      WRITE(6,2)PV,TOTALQ,QM,LOSTQ
2      FORMAT(/10X,'After ',F4.2,' P.V.s'/10X,'Tot. Heat ',
e'Inj. into Model is ',F8.2,' BTUs'/10X,'% of Tot. Heat ',
e'Inj. that is Remaining in Model is ',F5.2,'%'/10X,'% ',
e'of Tot. Heat Inj. Lost from the Model was ',F5.2,'%')
C
C
10     CONTINUE
      STOP
      END
```

Appendix C
Detailed Laboratory Manual

Table of Contents for Appendix C

1. MODEL PREPARATION.....	671
1.1 Preparation of a Homogeneous Model.....	671
1.1.1 Sealing the Model.....	671
1.1.2 Saturating the Model.....	671
1.2 Preparation of a Bottom Water Model	673
1.2.1 Introduction.....	673
1.2.2 Bottom Water Calculation.....	673
1.2.3 Formation of a Bottom Water Layer	674
2. DATA ACQUISITION SYSTEMS	676
2.1 Megadac.....	676
2.1.1 Getting Started.....	676
2.1.2 Megadac Initialization.....	677
2.1.3 Initializing Data Tables	678
2.1.4 Recording the Run Data.....	679
2.1.5 Quitting.....	679
2.2 Metrabyte.....	680
3. CLEANING THE MODEL	681
3.1 General Procedure.....	681
3.2 Cleaning the Glass Beads	682
3.3 Cleaning the Fibreglass Tray.....	682
3.4 Miscellaneous Comments	683

1. MODEL PREPARATION

1.1 Preparation of a Homogeneous Model

1.1.1 Sealing the Model

- a) Place the Wygal Particle Distributor on top of the frame of the fibreglass model.
- b) Fill the distributor with approximately 40 litres of 3 mm diameter glass beads using a 2 litre volume beaker.
- c) Allow beads to pass through a metering board onto the mesh screens in the distributor.
- d) Trim off excess beads off the model surface using a metal straight edge to ensure a flat surface with no protrusions.
- e) Apply a thin (1/8" thick), uniform layer of clear silicone sealant (Dow Corning RTV Sealant 732) around the edges of the fibreglass tray.
- f) Place 1/8" thick Celtite Neoprene Sponge on top of the tray and hence, covering the sealant.
- g) Place the (overburden) granite block on the tray and clamp the model.
- h) Turn on the vacuum pump and evacuate the fluid containers.
- i) Turn injection well off.
- j) Connect the production well to the the collection system.
- k) Aim the three way valve towards one of the containers and open the production well in the direction of the up dip saturation ports in order to evacuate the model.
- When the system is completely sealed, it will be indicated by a constant vacuum in excess of 68 cm of Hg which can be read from the adjacent manometer.

1.1.2 Saturating the Model

- a) Once the model is evacuated, tighten the clamps and tilt the model to 45°.
- b) Immerse the saturation tube in a vessel filled with 16 litres (V_{II}) of distilled water.
- c) Connect the saturation tube to the model.
- d) Open the injection well by turning it in the direction of the down dip saturation ports.
- Saturation occurs as a result of the suction force of the pump at the production end which draws the water from the down to up dip end of the model.
- e) Close the production well when the model is completely saturated with water which is indicated by water production in the collection flasks.

- f) Record the volume of water displaced during the water saturation process (V_1), disconnect the saturation tube and measure the volume of water remaining in the water vessel (V_f).
- g) Determine the volume of the pore volume (PV) of the bead pack:

$$\text{Pore Volume} = \left(\frac{\text{Total Initial}}{\text{Water Volume}} \right) - \left(\frac{\text{Amount of Water}}{\text{Displaced}} \right) - \left(\frac{\text{Final Volume}}{\text{of Water Remaining}} \right)$$

$$PV = V_{ti} - V_1 - V_f$$

Since the bulk volume of the model is 42005 cc, the porosity may be obtained:

$$\phi = \left(\frac{PV}{\text{Bulk Volume}} \right) \times 100\% = \frac{PV}{42005 \text{ cc}} \times 100\%$$

- h) Place the saturation tube in a 20 litre pail of Faxam-100 oil and reconnect it to the injection ports.
- i) Open the production wells and collect all fluid production in the pre-evacuated collection flasks.
- j) Close the production saturation port when oil saturation is complete.
- ~ This is signified when water is no longer produced, that is, when the bead pack has reached its irreducible water saturation (S_{wi}).
- k) Measure the amount of water displaced during water saturation (V_2).
- l) Calculate the hydrocarbon pore volume (HYC PV):

$$\left(\frac{\text{Hydrocarbon}}{\text{Pore Volume}} \right) = (\text{Pore Volume}) - \left(\frac{\text{Amount of Water Displaced}}{\text{During Oil Saturation}} \right)$$

i.e. HYC PV is the amount of oil taken into the model

$$HYC PV = PV - V_2$$

Thus, the initial oil saturation is

$$S_{oi} = \frac{HYC PV}{PV} \times 100\%$$

Since the initial gas saturation is assumed to be zero (S_{gi}) unless otherwise specified as in the case of a gas run, the irreducible water saturation can be calculated since

$$S_{oi} + S_{wi} + S_{gi} = 1, \text{ but } S_{gi} = 0$$

Hence, $S_{wi} = 1 - S_{oi}$

- m) Disconnect the saturation tube and production well.
- n) Return the model to the horizontal position.
- o) Push the model into the walk-in cooler.

- p) Turn on the cooler thermostat to 37.5°F (3°C).
 ~ It takes 24 hours to cool the entire model to 3°C.

1.2 Preparation of a Bottom Water Model

1.2.1 Introduction

The primary objectives are:

- to simulate a bottom water layer using a layer of frozen 5% NaCl solution
- to measure the refractive index of displaced water during the water/oil saturation process and hence, determine the quantity of bottom water remaining as a function of total gross model thickness

1.2.2 Bottom Water Calculation

- Express the thickness of bottom water (t) required as a percentage of gross model thickness.
- Assume: $\phi_{avg} = 34\%$.
- From the *Science Data Book*, $\rho_{NaCl} = 2.165$ g/cc and $\rho_{H_2O} = 1.000$ g/cc at 293 K.
- Calculate the average pore volume (PV_{avg}) of the model for the given situation:

$$PV_{avg} = \phi_{avg} \times V_b$$

where: $V_b = 42005$ cc = bulk volume

- Determine the pore volume (V_p) that the bottom water of thickness ' t ' occupies:

$$\frac{\text{total model thickness (= 2.5")}}{t} = \frac{PV_{avg}}{V_p}$$

- Include a correction volume in V_p to account for bottom water loss due to melting during saturation: $V_p' = V_p + \text{Correction}$
- In order to determine the quantities of NaCl and H₂O required to make a 5% (by weight) NaCl solution, the following equation is solved by trial and error:

$$V_p' = \frac{m_{H_2O}}{\rho_{H_2O}} + \frac{m_{NaCl}}{\rho_{NaCl}} \quad \text{where } m_p = 0.95m_{H_2O} + 0.05m_{NaCl}$$

Sample Calculation 1. 10% Bottom Water Mixture (10% BW)

- For 10% BW (% gross model thickness):

$$t = (10\%) \times 2.5" = 0.25"$$

- b) Given: $\phi_{avg} = 34\%$ and $V_b = 42005 \text{ cc}$,

$$PV_{avg} = 34\% \times 42005 \text{ cc} = 14282 \text{ cc}$$

- c) The pore volume that the bottom water occupies is:

$$\frac{2.5''}{0.25''} = \frac{14282 \text{ cc}}{V_p}; V_p = 1428 \text{ cc}$$

- d) Add a correction factor of 600 cc to the total volume of brine required to compensate for melting:

$$V_p' = 1428 \text{ cc} + 600 \text{ cc} = 2028 \text{ cc}$$

- e) If it is assumed that the total mass of the BW required is 2085 g:

$$m_{H_2O} = 0.95 \times 2085 \text{ g} = 1981 \text{ g}$$

$$m_{NaCl} = 0.05 \times 2085 \text{ g} = 104 \text{ g}$$

- f) Check to see that the volume calculated using the masses and densities correspond to the required volume of V_p' which was determined in Step (d):

$$V_{H_2O} = \frac{1981 \text{ g}}{1.000 \text{ g/cc}} = 1981 \text{ cc}; V_{NaCl} = \frac{104 \text{ cc}}{2.165 \text{ g/cc}} = 48 \text{ cc}$$

$$\text{Hence, } V_{p \text{ calculated}}' = 1981 \text{ cc} + 48 \text{ cc} = 2029 \text{ cc}$$

- g) If V_p' calculated does not agree with V_p' required within a $\pm 10 \text{ cc}$ tolerance then reiterate on Step (e) by assuming another value of total mass required for 10% BW.

1.2.3 Formation of a Bottom Water Layer

- Pour the required volume of 5% NaCl solution into the fibreglass model.
- Sprinkle enough glass beads into the tray using a 200 ml beaker to cover the bottom water solution.
- Add an additional thin layer of beads to the brine to compensate for water swelling due to freezing.
- Push the model into the walk-in cooler in preparation for freezing.
- Place 40 litres of dry glass beads into the cooler.
- Close the cooler and adjust the thermostat to -30°F (-34°C).
- Freezing generally takes approximately 24 hours for bottom water thickness variations up to 50% of the total gross model thickness.
- When the bottom water is completely frozen, pack the remainder of the model with the frozen beads using the Wygal Particle Distributor.
- Skim off any excess beads using a straight edge.

- i) Seal and saturate the bottom water model using the same procedure which is applied to the homogeneous model.
- ~ The purpose of using frozen beads and cold water instead of room temperature materials are simply to act as a heat sink by minimizing the thawing effects of the bottom water layer during the saturation process.
- j) Measure the refractive index of each sample to determine the amount of bottom water which has melted using the lever rule.
- ~ A plot of refractive index versus the percentage of NaCl in solution was constructed for various %NaCl combinations. From the linear relationship, which was achieved and is shown below as Figure 1A, it was determined that 0% NaCl corresponded to 0% bottom water and had the refractive index of distilled water, 1.33246 at 25.5°C. Similarly, 5% NaCl corresponded to 100% bottom water and had the refractive index of distilled water, 1.3410 at 25.5°C.

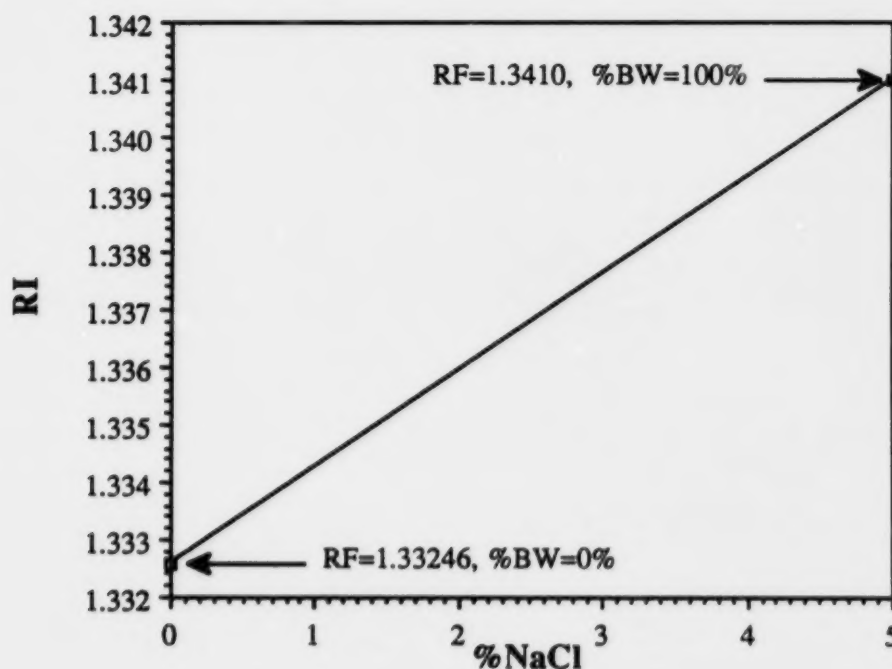


Figure 1C. A plot of refractive index versus %NaCl.

Sample Calculation 2. %BW Loss Due to Melting Using Refractive Indices

- a) Given: $RI = 1.3350$ at $25.5^{\circ}C$
 Sample Volume = $V = 1200$ cc
 PV = 14000 cc

Volume of Bottom Water Frozen Initially = $V_p' = 2029$ cc

Find: The volume of BW remaining in the model after this sample is taken.

- b) From Figure 1A, %NaCl = 1.5% at RI = 1.3350. Using the lever rule determine %BW in sample,

$$\frac{\%BW \text{ in Sample}}{100\%BW} = \frac{1.5\%NaCl}{5\%NaCl}$$

$$\text{Thus, \%BW in Sample} = \frac{1.5\%NaCl}{5\%NaCl} \times 100\%BW = 30\%BW$$

- c) Calculate:

$$\begin{aligned} \text{BW Produced} &= \%BW \text{ in Sample} \times \text{Sample Volume} \\ &= 30\% \times 1200 \text{ cc} \\ \text{BW Produced} &= 360 \text{ cc} \end{aligned}$$

- d) Then, solve:

$$\begin{aligned} \text{BW Remaining} &= V_p' - (\text{BW Produced}) \\ &= 2029 \text{ cc} - 360 \text{ cc} \\ \text{BW Remaining} &= 1669 \text{ cc} \end{aligned}$$

- e) Bottom water thickness can now be determined:

$$\frac{2.5''}{t} = \frac{14000 \text{ cc}}{1669 \text{ cc}}$$

$$t = 0.298'' = 11.9\%BW(\% \text{gross model thickness})$$

$$\text{where } \% \text{gross thickness} = \frac{0.298''}{2.5''} \times 100\% = 11.9\%$$

2. DATA ACQUISITION SYSTEMS

2.1 Megadac

The following procedures are used to generate and record the data from steam injection experiments in a scaled physical model using the Megadac 2000 data acquisition unit. This system has now been replaced by the Metrabyte and Labtech Unit which is described in Section 2.2.

2.1.1 Getting Started

- Turn on the IBM Personal Computer, MEGADAC SYSTEM 2000 and the EPSON Printer.
- To change the directory, type CD\OPUSHELEN.
- To run the OPUS software package, type OPUS.

- d) Press **PF5** (**MEASUREMENT USING MEGADAC**) followed by **RETURN**.
- If the Megadac and IBM screen both have the correct time and date, and no other error message appears on either screen, then go to Step 2.1.3 otherwise go to Step 2.1.2.

2.1.2 Megadac Initialization

Part A

Type **PF9** for initialization instructions which are as follows:

- a) Press **RESET** button on Megadac 2000.
 - b) Press **SETUP** button on Megadac 2000.
 - c) Type **2** to set the mode.
 - d) Type **99**.
 - e) Press **ENTER** button on Megadac 2000.
 - f) Turn off Megadac 2000.
 - g) Turn on Megadac 2000 to establish initial baud rate.
 - h) Wait for the **REMOTE** light on the Megadac panel to appear. Then, press **PF10**.
- If no error is indicated on the IBM screen, then proceed to Step 2.1.3. However, if there is still an error in either the time, date or any other information printed on the screen, then the time and date must also be reset as listed in Step 2.1.2: Part B.

Part B

- a) Press **RESET** button on MEGADAC 2000.
- b) Press **SETUP** button on MEGADAC 2000.
- c) Press **1** to set the time.
- d) Type the time and date in the following sequence:
date month year hour minute seconds or dd mm yy hr mi ss

— *Please note:*

- ~ There are no spaces in this character chain.
- ~ Each item consists of two integers.
- ~ Time format is based on 2400 hours.

— *For example,*

May 19, 1990 at 10:30:35 am is typed in as 190590103035.

October 2, 1990 at 3:45:00 pm is typed in as 021090154500.

- e) Turn off Megadac 2000 to initialize baud rate.
- f) Turn on Megadac 2000.
- g) When the **REMOTE** light comes on, press **PF10**.
- ~ If no error message appears on Megadac or on the IBM screen, go to Step 2.1.3.

2.1.3 Initializing Data Tables

- a) Press **PF4 (RUN — DATA TO DISK)** and then **RETURN**.
- b) A screen from the **OPTIM USER'S SOFTWARE** is generated to record **SCAN AS PER TABLE**. Type **PREPARE** in the grey box beside the title "Name of Experiment Table". This is done in order to check if the thermocouples are all working.
- c) Press **PF10** to accept the **PREPARE** file.
- d) Suffix to be given to data file: **D__** is shown on the screen. Type in the grey box the suffix number, such as 67 so the data will be recorded as **D67**.
- e) Press **PF10** again to continue in addition to checking the thermocouples and pressure transducers on the model. The Optim User's Software Package converts voltage readings to temperature and pressure units for the respective sensors. White numbers refer to positive values (kPa or °C) while red numbers indicate negative values (kPa or °C). Thermocouple temperatures should be between zero and three degrees Celsius (0 to 3°C). Check and adjust any thermocouple or transducer connections with temperature and pressure readings in excess of a factor of 1000. Possible sources of error are loose connections between the data cable and sensor junction, broken thermocouples or electrical shorts in data cables which connect the sensors with Megadac.
- f) **OPUS** and **Megadac** will continue scanning the thermocouples until all reading are satisfactory. To stop scanning, press **PF8**.
- g) To return to the **OPUS** menu, press **PF10**.
- ~ Once the thermocouples are producing acceptable results, the next stage of the program is to allow **OPUS** to record all the experimental results in the IBM hard drive and print all the transmitted data simultaneously on the **EPSON** printer.
- h) Press **PF4 (RUN — DATA TO DISK)** and **RETURN**.
- i). This time the "Name of Experiment Table" is typed in as **RUNS** instead of **PREPARE** as in Step (b). Then type **RETURN** to accept the table.
- j) The **RUNS** table records the experimental results. To receive a printed copy simultaneously with the displayed results, press **RETURN** to cursor the grey box

to the desired selection: **PRINTED/MEASURED RESULTS**. Type **1** beside **PRINTED/MEASURED RESULTS**. This command will allow the EPSON printer to print one measured result for each one displayed on the IBM terminal.

- k) Press **PF10** to return to the screen.
- l) Press **PF10** to accept the new input data.

2.1.4 Recording the Run Data

- Record the data only pertinent to the run such as solvent injection and steam injection. Well connection time is ignored.
- a) When the solvent inlet is connected to the injection well, begin scanning when solvent injection begins. This is done by pressing **PF10** which stores the run data for each 30 second scan. Record the scan numbers from the IBM screen when solvent injection begins and ends.
- b) The solvent port is then disconnected and is replaced by the steam port. The objective is to open the production well approximately half ($1/2$) a scan before the injection well. First, open the production well and record that scan number. Second, open the injection well on the following scan and record that scan number. It is essential to record the scans at which each sample is collected as well as the instant the pump is shut off (ie. when the experiment ends). Also record additional scans, such as pressure buildup and pore volume injected, as they are helpful when analyzing the results.
- It is desired to maintain a production pressure between 80 and 90 kPa. If the pressure exceeds this range then the seal will most likely break and destroy the vacuum; the results from the run will then be useless.
- d) Other items which should be recorded include the refractive index of the samples, the total volume of the sample and the respective volumes of solvent and oil in the cylinder.

2.1.5 Quitting

- a) To stop scanning and storing the data, press **PF8**.
- b) To return to the OPUS menu, press **PF10**.
- c) To terminate the OPUS program, press **PF10**.
- d) To exit OPUS and return to DOS, press **PF10**.
- e) Finally, type **YES** or **Y** when prompted to exit the OPUS package.

2.2 Metrabyte

The Megadac 2000 data acquisition system broke down prior to the initiation of Run 70B. After evaluating situation, it was decided that it would not be economical to repair the Megadac unit or the Optim User's software package. Rather, it was more feasible to replace Megadac with another acquisition system. A Metrabyte data acquisition system was chosen primarily because of its low cost, its ability to interface with the existing IBM personal computer which was used to process Megadac 2000 data, easy accessibility for necessary repairs as well as the availability of consultants. In addition, an integrated data acquisition, control and analysis software package called Labtech Notebook was also purchased.

One of the advantages of choosing Metrabyte is its expansion capability. The central processing unit is an eight channel 12 bit high speed A/D converter and timer/counter board for the IBM PC called the DAS-8 board. The EXP-16 multiplexer offers a relatively inexpensive way to expand the input capabilities of the DAS-8. Each EXP-16 has 16 fully differential inputs that can be multiplexed into a single A/D board input channel. The EXP-16 is ideal for measuring thermocouple inputs because of the temperature sensor on the board which permits the cold junction temperature (CJC) to be monitored. Although it is possible to have a maximum of eight EXP-16 panels attached to one DAS-8 multiplexer, the steam injection experiments require only a maximum of 37 J-type thermocouples and 4 pressure transducers. Therefore, four EXP-16 boards were ordered and were installed according to Figure 2B:

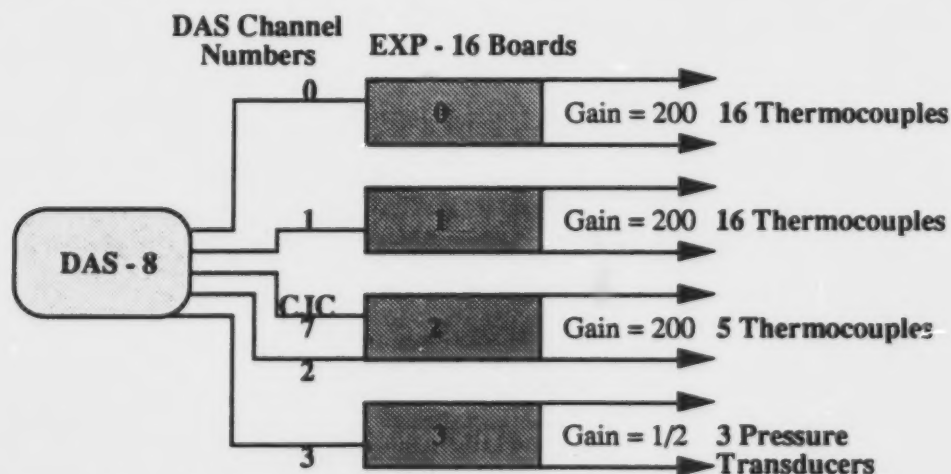


Figure 2C. A schematic of the Metrabyte data acquisition unit.

Labtech Notebook processes all raw thermocouple (mV) and pressure transducer (mV) measurements and automatically converts them into real values of temperature (degrees Celsius) and pressure (kPa) as a function of real time (seconds or minutes). No programming was required because Labtech is menu driven. To initiate Labtech, simply change the Main directory to the Notebook one by typing the DOS command `cd\nb` followed by `nb` which will execute the program. In addition, Notebook includes foreground/background operations which permits the user to perform other tasks while data is being collected. Furthermore, Labtech Notebook interfaces all data files, which are stored in an ASCII file format, to IBM software packages, such as Lotus 1-2-3 or Lotus Symphony. It is important to note that a hard drive is preferable in order to maximize efficiency due to the large size of this software package. In addition, the hard drive must be referred to as 'C' if it is desired to use Labtech's intallation program (Version 4.36), otherwise Notebook must be installed manually.

3. CLEANING THE MODEL

3.1 General Procedure

- a) Remove the clamps from the model.
- b) Bleed off the vacuum in the model by opening one of the quick-connects. If this is not done, then the top granite block will tend to stick to the Neoprene sheet and consequently, the fibreglass tray as a result of the vacuum created during the run.
- c) Remove the top block using the hydraulic jack.
- d) Pull the cart containing the lower block and tray away from the jack into an open area for cleaning.
- e) Remove the Neoprene sheet.
- f) Shake the sheet to remove any glass beads which may be imbedded in the Neoprene.
- g) Dispose of the Neoprene sheet in a waste container since it will not be reused in future runs.
- h) Scoop out the glass bead pack from the model using a small beaker and place them into several plastic pails.
- Try to avoid bending the thermocouples since they break very easily.
- i) Clean the beads as per the instructions in Section 3.2.
- j) Clean the fibreglass model as per the instructions in Section 3.3.

3.2 Cleaning the Glass Beads

From past experiences, it is more desirable to clean the glass beads in smaller portions in a 10 litre plastic pail instead of a 20 litre one in order to maximize task efficiency.

- a) Fill one-third ($1/3$) to half ($1/2$) of a 10L pail with the glass beads.
- b) Add approximately 100 to 200 ml of SLIK #5 degreaser to the pail.
- c) Immerse the beads in hot water.
- d) Wash the beads in the degreaser-water solution by hand to remove oil and any residual solvent from the beads.
- SLIK #5 degreaser is water soluble, so it may be poured directly into the sink.
- e) Rinse the beads with hot water and add 50 mL to 100 mL of Sparkleen soap to the pail. Clean the beads and empty the pail.
- f) Repeat step (e) and continue to rinse the glass beads until there is no more oil or soap on them.
- Usually, one wash cycle in degreaser and two wash cycles in Sparkleen followed by four to five rinses in hot water are sufficient.
- The average time required to clean 5 L to 7 L of beads is approximately 10 to 15 minutes.
- g) Pour the glass beads into the metallic bead driers which are situated on risers.
- h) Allow any excess water to drain out of the driers in order to expedite the drying period.
- i) Connect tubing from the driers to the air inlet valve.
- j) Turn on the air valve and inject air into the bead drier.
- This process may be left unattended and usually takes between 18 to 24 hours to complete.

3.3 Cleaning the Fibreglass Tray

- a) Scrape off the silicone sealant layer using a chisel or sharp metal straight edge, such as a dull knife blade, being careful not to scratch the fibreglass tray.
- b) Remove all trimmings and dispose in waste basket.
- c) Tilt the model 45° using the same the procedure described for model saturation.
- d) Mix 200 mL to 300 mL of degreaser with 4 litres of hot water. Pour half of the solution into the up dip side of the model to remove all traces of oil from the model.
- e) Drain the model using a siphon.

- ~ A siphon is the quickest and most efficient way to remove the liquid waste. This is done by sealing one end of a piece of rubber tubing with one thumb and adding water in the other end until the tubing is completely filled. Then, seal this end immediately trying to eliminate any air bubbles. Place one end in the bottom of the model and the other in a disposal pail on the floor. Remove both thumbs simultaneously. The suction force caused by the height differential and thus, pressure differences between both ends should draw the water and any remaining beads from the model into the waste pail.
- f) Add the remainder of the degreaser solution to the model and drain the waste.
- g) Rinse the model with hot water and drain with siphon. Repeat until there is no more oil in the model.
- h) Dry the model with Kimtuff wipers.
- ~ Kimtuff disposable wipers are used to absorb residual oil and solvents from the model.
- i) Apply Varsol to the fibreglass tray and its edges using a wash bottle.
- j) Wipe the tray and edges with Kimtuff wipers.
- k) Apply acetone to the fibreglass tray and its edges using a wash bottle.
- ~ Both Varsol and acetone are used because some hydrocarbons break down better in Varsol than in acetone and vice-versa. It is hoped that using both solvents can remove all traces of the hydrocarbons used in the experiments, such as Faxam-100 and heavy virgin naptha. Because the use of toluene is restricted to areas with sufficient ventilation like fume hoods, it is not used in the steam injection experiments which are run in open laboratory conditions.
- l) Dry the tray and edges with the wipers.
- m) Lower the model.
- n) Straighten any bent thermocouples and replace any broken ones.
- ~ New thermocouples are replaced by inserting them through the ferrels and fittings into the fibreglass tray to the desired length. Tighten the fittings and seal all exposed areas with the silicone sealant to ensure that no areas will be potential sources where the vacuum may escape.

3.4 Miscellaneous Comments

- a) Any containers storing solvent must be emptied in a waste receptacle not in the sink as solvent is not water soluble and will corrode the sink and its pipes.

- b) Scrub the glass cylinders, flasks and beakers with beaker brush using Sparkleen detergent and hot water.
- c) Plastic cylinders and beakers are tipped upside down on top of a layer of Kimtuff wipers and allowed to drain out any excess oil. Sparkleen is primarily used for glassware and is not suitable for cleaning plastics. However, common household dishwashing liquid detergent is a very effective and inexpensive way to clean plastic containers of all traces of oil.
- d) Celtite Neoprene sponge is cut in 3'x3' sheets using a utility knife. Epoxy joined portions of the Neoprene roll are cut off as they are often sources of seal leakage and hence, result in vacuum loss. Exact cutting precision is not necessary since the flexible and cushy nature of Neoprene allows it to conform to all situations.

Appendix D

Contour Plotting Programs and Graphing Procedures

Table of Contents for Appendix D

1. INTRODUCTION.....	687
2. CONNECTING TO MTS FROM MICROCOMPUTERS	687
2.1 Signing on to MTS via an IBM Personal Computer.....	687
2.2 Signing on to MTS via a Macintosh Computer.....	687
3. GENERATING DISSPLA PLOTS FROM AN IBM TERMINAL.....	688
3.1 Top View Temperature Profiles.....	688
3.2 Cross-Section Temperature Profiles.....	690
4. RUNNING TELL-A-GRAF PLOTS FROM AN IBM.....	691
5. PLOTTING FROM A MACINTOSH TO AN HP DEVICE	692
5.1 General Comments	692
5.2 Graphing Procedures for DISSPLA Plots using the Macintosh.....	693
5.3 Generating Tell-A-Graf Plots from the Macintosh.....	694
5.4 Cable Schematics	695
6. CONTOUR PLOT PROGRAMS.....	695
6.1 Top View Temperature Profiles.....	695
6.2 Injector to Producer Cross-Section Temperature Profiles.....	698
6.3 Macro Program.....	699
6.4 MTS Sigfile.....	701
7. DATA FILE CONSTRUCTION.....	701
7.1 General Procedure	701
7.2 Pore Volume Injected.....	702
7.3 Solvent Slug Calculation.....	702
7.4 Top View Data Files.....	703
7.5 Cross-Section Data Files.....	704

1. INTRODUCTION

The *DISSPLA* graphics package is used to generate the temperature contours for both the top view of the model and the model cross-section for each run. *DISSPLA* and Tell-A-Graf programs are all compiled in the MTS (Michigan Terminal System) main frame computer system. The Tell-A-Graf software package is used to plot additional experimental results, such as "Cumulative Oil Recovery versus Pore Volume Injected" and "Temperature-Viscosity Profile for Ideal and Actual Model Oil". Additional programs were written in a macro file in MTS to increase the efficiency of generating *DISSPLA* and Tell-A-Graf plots. Appendix B deals with the procedures required to produce many of the plots in this thesis.

2. CONNECTING TO MTS FROM MICROCOMPUTERS

2.1 Signing on to MTS via an IBM Personal Computer

- a) Turn on IBM Personal Computer screen and hard drive.
 - b) Switch "Data Director" switch to position A (MTS).
 - c) Type `cd\` to return to the main directory.
 - d) Type `pctie`.
 - e) Ensure that the Gandalf modem is set to '04' before turning on the switch in order to connect to MTS.
 - f) Type `signon CSID` or `sig CSID`.
- Although MTS recognizes uppercase as well as lower case commands, the *DISSPLA* and Tell-A-Graf packages require all instructions be typed in uppercase letters.
- g) Type 'password' when prompted by MTS.

2.2 Signing on to MTS via a Macintosh Computer

- a) Turn on Macintosh computer and its hard drive.
- b) Switch "Data Director" switch to position A (MTS).
- c) Open the communications folder containing the program Mactie by double clicking on the icon.
- d) Open the MACTIE application.
- e) Again, as in the case of the IBM, ensure that the Gandalf modem is set to '04' before turning on its switch to connect to MTS.
- f) Type `signon CSID` or `sig CSID`, followed by the 'password'.

3. GENERATING DISSPLA PLOTS FROM AN IBM TERMINAL

3.1 Top View Temperature Profiles

- a) Type cplot then press RETURN, hereafter denoted as Ret.

Screen output lists the cplot portion of the Macro file located in Section 6.3:

ENTER THE NAME OF THE *DISSPLA FILE:

- b) Type the name of the DISSPLA file in Section 6.1 which will generate a top view profile, TOPVIEW, and enter Ret.

Screen output is:

ENTER THE NAME OF THE DATA FILE:

- c) Type the name of the desired data file, such as R39.025 and press Ret.

Screen output lists a portion of the TOPVIEW program which can be edited:

```
CALL HEADIN ('(T)EMPERATURE (P)ROFILE FOR$',100,1.0,4)
CALL HEADIN ('0.25 (P)ORE (V)OLUMES (I)NJECTED$',100,1.0,4)
CALL HEADIN ('$',100,1.0,4)
CALL HEADIN ('$',100,1.0,4)
CALL XNAME ('(H)ORIZONTAL (M)ODEL (L)ENGTH, INCHES',37)
CALL YNAME ('(V)ERTICAL (M)ODEL (L)ENGTH, INCHES',35)
CALL INTAXS
CALL GRAF (0,4,32,0,4,32)
CALL MESSAG ('(F)IGURE 1: (R)UN 39$,100,1.8,7.0)
```

- d) Cursor to the headings in bold letters and edit them as required for each run.
e) Press CRTL and Ret simultaneously to quit the visual edit mode in MTS.

Screen output is:

```
$EMPTY -LOAD#
EMPTY -PLOT
EMPTY -PLOTHP
RUN *FORTG SCARDS=TOPVIEW
RUN -LOAD#+*DISSPLA 5=X39.025 9=-PLOT
RUN *PLOTSEE T=5 PAR=-PLOT HP7475F PAGEFILL RETURN
EDIT -PLOTHP D1
```

Upon the completion of the DISSPLA program, the screen will list the following before the plot file is transferred to the IBM hard drive:

END OF DISSPLA 9.0 -- 4881 VECTORS GENERATED IN 1 PLOT FRAMES,
PROPRIETARY SOFTWARE PRODUCT OF ISSCO,SAN DIEGO,CA. 11608

VIRTUAL STORAGE REFERENCES; 7 READS; 0 WRITES.:1 LINE DELETED

File transfer is initiated by the following command:

CONTROL *MSOURCE* FT BREP MTS -PLOT HP C:R39.025

Upon the completion of the file transfer from MTS to the IBM, the screen output is:

#:FILE TRANSFER - HOST SIDE NORMAL EXIT

- f) Type %EX and Ret to exit pctie and to enter DOS.
- g) Turn "Data Director" switch to position B (Hewlett Packard 7550A Plotter).
- h) Type DIR and Ret to check the remaining amount of disk space in the hard drive and to confirm if the file has been transferred successfully to the main directory. There should be a plotter file in the main directory called R39.025.
- i) Type DOPLOT and Ret to initialize the HP plotter.
- ~ Doplplot and the communications commands are software programs installed in the main directory of the IBM which permit the plotter and computer to interface.

Screen output is:

MODE COM1:9600,N,8,1,P

- j) Type COPY filename1 COM1 and Ret.
- ~ In this case, type: COPY R39.025 COM1
- ~ The HP 7550A should begin plotting the temperature contours immediately. If it does not,
 - i) check the printer -- IBM connection to ensure that it is securely attached
 - ii) check to see if the paper has been fed properly. Usually, the paper needs to be reloaded every time the HP7550A is turned on.
- k) To reload the plotter paper automatically, type COPY PAGE COM1. Page is simply a filename in the main directory containing the command "PG1;" which will prompt the plotter to feed one sheet of paper through the tray thereby loading the paper. If it is desired to feed two sheets through the plotter, then replace "PG1;" by "PG2;".
- ~ To reload the paper manually, press the LOAD/UNLOAD button on the HP plotter.

3.2 Cross-Section Temperature Profiles

The procedure for generating injector to producer cross-section profiles is the essentially the same as the one used in Section 3.1 to plot top view temperature profiles, with the exception of a few minor changes listed in this section. For detailed explanations of the of the plot generation commands, please consult Section 3.1.

- a) Type **cplot** then press **RETURN**, hereafter denoted as **Ret**.

Screen output lists the cplot portion of the Macro file located in Section 6.3:

ENTER THE NAME OF THE *DISSPLA FILE:

- b) Type the name of the *DISSPLA* file in Section 6.2 which will generate a cross-section profile, *XSECTION*, and enter **Ret**.

Screen output is:

ENTER THE NAME OF THE DATA FILE:

- c) Type the name of the desired data file, such as *X74.075* and press **Ret**.

Screen output lists a portion of the XSECTION program which can be edited:

```
CALL HEADIN ('(F)IGURE 7: (R)UN 74 (T)EMP (P)ROFILES',
+100,1.0,4)
CALL HEADIN ('(I)NJECTOR TO (P)RODUCER (C)ROSS-(S)ECTIONS$',
+-100,-1.0,4)
CALL HEADIN ('0.75 (P)ORE (V)OLUMES (I)NJECTED$',
+100,0.8,4)
CALL HEADIN ('$',100,1.2,4)
CALL XINTAX
CALL GRAF (0.,5.,45.,0.,5,2.5)
```

- d) Cursor to the headings in bold letters and edit them as required for each run.
e) Press **CRTL** and **Ret** simultaneously to quit the visual edit mode in MTS.

Screen output is:

```
$EMPTY -LOAD#
EMPTY -PLOT
EMPTY -PLOTHP
RUN *FORTG SCARDS=XSECTION
RUN -LOAD#+*DISSPLA 5=X74.075 9=-PLOT
RUN *PLOTSEE T=5 PAR=-PLOT HP7475F PAGEFILL RETURN
EDIT -PLOTHP D1
```

Upon the completion of the DISSPLA program, the screen will list the following before the plot file is transferred to the IBM hard drive:

END OF DISSPLA 9.0 -- 4881 VECTORS GENERATED IN 1 PLOT FRAMES,
PROPRIETARY SOFTWARE PRODUCT OF ISSCO,SAN DIEGO,CA. 11608
VIRTUAL STORAGE REFERENCES; 7 READS; 0 WRITES.:1 LINE DELETED

File transfer is initiated by the following command:

CONTROL *MSOURCE* FT BREP MTS -PLOT HP C:X39.025

Upon the completion of the file transfer from MTS to the IBM, the screen output is:

#:FILE TRANSFER - HOST SIDE NORMAL EXIT

- f) Type %EX and Ret to exit pctie and to enter DOS.
- g) Turn "Data Director" switch to position B (Hewlett Packard 7550A Plotter).
- h) Type DIR and Ret. There should be a plotter file in the main directory called X39.025.
- i) Type DO PLOT and Ret to initialize the plotter.
- j) Type COPY filename1 COM1 and Ret.
- ~ In this case, type: COPY X74.075 COM1
- k) To reload the plotter paper automatically, type COPY PAGE COM1 or press the LOAD/UNLOAD button on the HP plotter.

4. RUNNING TELL-A-GRAF PLOTS FROM AN IBM

All Tell-A-Graf plots are generated through MTS. The signon procedure is the same as the one described in Section 1.

- a) If the computer terminal has graphics capability, such as a video card for the IBM or is a Macintosh computer, the Tell-A-Graf plot may be viewed on the computer screen through MTS prior to sending it to the plotter. This is done by typing %T4010 to enter the graphics mode.
- b) Type TAG to run the Tell-A-Graf program.
- ~ TAG is a source file listed Section 6.3.
- ~ If the TAG is not available in the Macro program, then it is necessary to type:
RUN *TELLAGRAF.
- c) Type include "plot name". Then Ret.
- d) Press Ret again.
- e) Type send.

Output is:

9 was referenced, but unit is not set.
 Enter a new file/device name, "CANCEL", or "HELP".
 ?

Type -AA and Ret (-AA is a temporary file to which the plot is sent).

- f) Type quit. and Ret.

Output is:

END OF TELLAGRAF 4.0 -- 3312 VECTORS GENERATED IN 2 PLOT
 FRAMES.
 PROPRIETARY SOFTWARE PRODUCT OF ISSCO, SAN DIEGO, CA.
 #08:07:23 T=1.234 RC=0

- g) Press CTRL and ESC to return to the MTS write screen.

- h) Type the following:

RUN *PLOTSEE T=5 PAR=-AA HP7475f PAGEFILL RETURN and
 then press Ret.

Output is:

...For information about the placement of HP7475 plots,
 ...see the file "LEEN:PLOTSEE.NOTE".
 #08:11:05
 End of plot file
 #08:11:12 T=0.0462 RC=0

- i) Type **EDIT -PLOT HP DEL 1** and Ret.
- j) Type **%FT BREP MTS -PLOT HP C:plot name** and then Ret.
- k) Type **%EX** to exit MTS.
- l) Turn "Data Director" switch to position B (Plotter).
- m) Type **DO PLOT** for plotter initialization.
- n) Type **COPY plot name COM1** to print the graph.
- o) Type **COPY PAGE COM1** to reload the paper.

5. PLOTTING FROM A MACINTOSH TO AN HP DEVICE

5.1 General Comments

To plot any graphs using a Hewlett Packard plotter, one requires a copy of the "File to HP7475" plotting program (which is available through the University of Alberta Computing Services), a MacWrite application (Version 5.01 and up) and a cable with the

same internal components as an Imagewriter cable are required in order to be able to plot graphs from the Macintosh to an HP plotter.

The "mock" Imagewriter cable, as shown schematically in Section 5.4, connects the Macintosh to the plotter and attempts to generate the illusion to the Macintosh that the HP plotter is really an Imagewriter. Thus, to plot a graph, one chooses the Imagewriter printer device and then opens the "File to HP7475" application which will allow the user to open the desired plot file, and then print the MacWrite document. The computer believes that it is printing a MacWrite document using an Imagewriter when in reality it is sending the material to an HP the plotter. Although the programs are written for the HP7475, they have also been tested successfully on the HP7550A and HP7470A.

MACPLOT is a macro program in MTS which will automatically compile and transfer any *DISSPLA* program to a Macintosh computer. MACPLOT is the Macintosh equivalent to the CPLOT program used for the IBM. Tell-A-Graf plots are first generated using the TAG macro and can be transferred using the TELPLOT macro. To avoid redundancy, the Macintosh commands are listed briefly in Section 5.2 and 5.3 without any detailed comments. All of the macros are listed in Section 6.3.

The primary difference between plotting from an IBM or Macintosh is that the IBM transfers the plot file in binary code (BREP) whereas the Macintosh appends the file (BAPP) during any transfer. In addition, sometimes the Mactie will prompt the user for a device, at which time "HP7475" will be typed. Hence, the command used to transfer a *plotsee file is

```
%FT BAPP MTS -PLOTHP {filename}
```

To send an MTS file via Mactie to the LaserWriter, simply type:

```
%FT MTS {MTS file to be printed} {Name of the printer file}
```

One will then quit Mactie, without necessarily signing off, and open the printer file, which is formatted as a MacWrite document, and print the file in the normal manner.

5.2 Graphing Procedures for *DISSPLA* Plots using the Macintosh

- a) Type `macplot` then press `Ret.`

- b) Type the name of the *DISSPLA* file when prompted, TOPVIEW for top view temperature contour profiles and X-SECTION for a cross-section profile, followed by entering **Ret**.
- c) Type the name of the desired data file, such as **X74.075** and press **Ret**.
- d) Cursor to the headings in bold letters and edit them as required for each run.
- e) Press **command** and **Ret** simultaneously to quit the visual edit mode in MTS. The *plotsee program and the file transfer commands are sourced automatically from the Macplot macro in Section 6.3 so there is no need to type any additional command.
- Occasionally, MTS asks: "What type of device are you on?". If this occurs, type: **HP7475**.

The file transfer is initiated by the following command:

CONTROL *MSOURCE* FT BAPP MTS -PLOT HP X39.025

- f) Type **%EX** and **Ret** or select quit to exit Mactie.
- g) Choose Imagewriter printer device.
- h) Open **File** to **HP7475** application.
- i) Select and open the desired plot file when prompted, in this case, X39.025 which is now in a MacWrite document.
- The Hewlett Packard plotter should begin plotting immediately otherwise check cable connections and open the plot file in MacWrite to ensure that the file was transferred properly and its contents are complete.

5.3 Generating Tell-A-Graf Plots from the Macintosh

- a) The Tell-A-Graf plot may be viewed on the computer screen through MTS prior to sending it to the plotter by selecting or typing **%T4010** to enter the graphics mode.
- b) Type **TAG** to run the Tell-A-Graf program.
- c) Type include **"plot name"**. Then **Ret**.
- d) Press **Ret** again.
- e) Type **send**.
- f) Type **quit**. and **Ret**.
- g) Press **command** and **Ret** to return to the MTS write screen.
- h) Type **source sigfile**.
- i) Type **TELPLOT** which will source the following commands:

Output is:

TYPE THE NAME OF THE *TELLAGRAF FILE TO BE TRANSFERRED:

- j) Type any name, for simplicity the title of the Tell-A-Graf file, which will correspond the file name in MacWrite to which the data will be transferred.

The resulting output will be:

```
RUN *PLOTSEE T=5 PAR=-AA HP7475f PAGEFILL RETURN
EDIT -PLOTHP DEL 1
%FT BAPP MTS -PLOTHP *TELLAGRAFILE
```

- k) Type %EX or command Q to exit MTS.
l) Repeat steps (h) and (i) in Section 5.2 to send file to HP plotter.

5.4 Cable Schematics

Because the objective used in sending Tell-A-Graf and *DISSPLA* plots to an HP plotter is to mislead the Macintosh computer into believing that the HP plotter is really an Imagewriter, certain cables must be constructed in the manner described in Figure 1D.

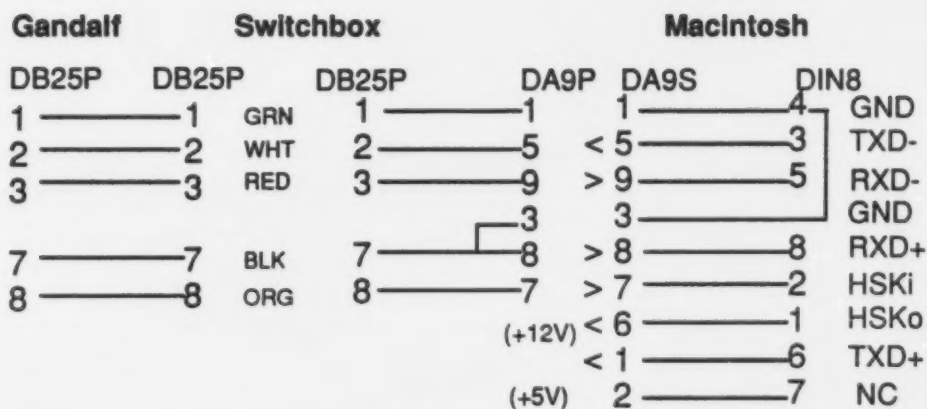
6. CONTOUR PLOT PROGRAMS**6.1 Top View Temperature Profiles**

- C The following DISSPLA program is used to generate a contour plot of two sets of
C X, Y, Z data, with Z representing the temperature at the given (X, Y) coordinates.
C

```
LOGICAL *1 FREE (1) /*'/
DIMENSION ZMAT (5,5)
DIMENSION IPAK (1000)
REAL DUMMY (2) /0.,0./
COMMON WORK (20000)
CALL PAGE (8.5,11.)
CALL PHYSOR (2.0,2.5)
CALL AREA2D (5.5,5.5)
CALL FRAME
CALL DUPLX
CALL BASALF ('L/CSTD')
CALL MIXALF ('STANDARD')
```

- C The following commands are used to generate both the text material and the plot
C axes:
C

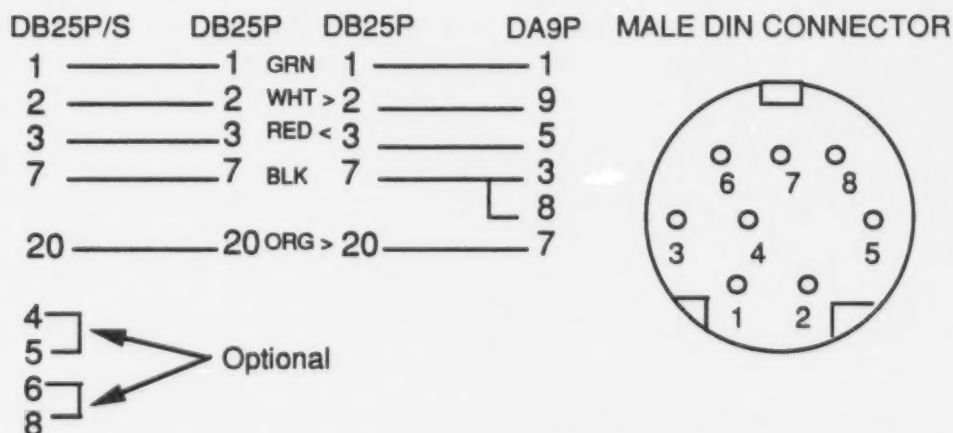
```
CALL HEADIN ('(T)EMPERATURE (P)ROFILE FOR$',100,1.0,4)
CALL HEADIN (' $',100,1.0,4)
```



Note: Above cable may be readily purchased.

H.P. Plotter or Imagewriter Switchbox

Macintosh



Cable schematics reprinted with the permission of:
R.K. Stefaniuk, E.E.T., U of Alberta Technical Services
1990-01-10

Figure 1D. Cable Schematics for Macintosh Computer to Modem/Plotter

```

CALL HEADIN ('$',100,1.0,4)
CALL XNAME ('(H)ORIZONTAL (M)ODEL (L)ENGTH, INCHES',37)
CALL YNAME ('(V)ERTICAL (M)ODEL (L)ENGTH, INCHES',35)
CALL INTAXS
CALL GRAF (0,4,32,0,4,32)
CALL MESSAG ('(F)IGURE 4: (R)UN 104$,100,1.8,7.0)
CALL MESSAG ('(S)TEAMFLOOD OF (B)OTTOM (W)ATER (M)ODEL$',
+100,1.0,6.7)

```

C
C
C

These DISSPLA commands are used to label the injection points:

```

CALL HEIGHT (0.12)
CALL MESSAG ('(I)NJECTION (W)ELL$', 100,4.4,-0.7)
CALL MESSAG ('(P)RODUCTION (W)ELL$',100,0.0,5.775)

```

C
C
C
C

These series of routines draw arrows from the two labels described above to the injection and production wells, respectively:

```

CALL VECTOR (5.5,-.5,5.5,-.25,2201)
CALL VECTOR (0.0,5.75,0.0,5.5,2201)

```

C
C
C

The following series generates legend text material:

```

CALL LINE$P (2.0)
CALL LINES ('(U)PPER (M)ODEL (T)EMPERATURE (C)$',IPAK,1)
CALL LINES ('(L)OWER (M)ODEL (T)EMPERATURE (C)$',IPAK,2)
CALL BGNMAT (5,5)
DO 20 J=1,2
    READ (5,FREE) N
    DO 10 I=1,N
        READ (5,FREE) X,Y,Z
        Z=Z+3.0
10    CALL GETMAT (X,Y,Z,1,0)
    CALL ENDMAT (ZMAT,0)

```

C
C
C

Contouring routines:

```

CALL BCOMON (10000)
CALL CONMAK (ZMAT,5,5,5.)
CALL CONMIN (1.5)
CALL CONDIG (0)
IF (J.EQ.2) GO TO 15
CALL SETCLR ('BLUE')
CALL CONLIN (0,'SOLID','LABELS',1,10)
GO TO 16
15 CALL SETCLR ('RED')
CALL CONLIN (0,'DASH','LABELS',1,9)
16 CONTINUE
CALL RASPLN (0.2)
CALL CONTUR (1,'LABELS','DRAW')

```

C
20
C
C

CONTINUE

The following commands generate a legend with the appropriate colour markers:

C

```

CALL SPCMOD
CALL LEGLIN
CALL CURVE (DUMMY,DUMMY,2,0)
CALL CURVE (DUMMY,DUMMY,2,0)
CALL MYLEGN (' ',1)
CALL LEGEND (IPAK,2,0.,-1.)
CALL ENDPL (0)
CALL DONEPL
STOP
END

```

C

C

C

C

This subroutine is used to define different textures between the line types and colours:

```

SUBROUTINE MYSPEC (IENTRY)
GO TO (1,2) , IENTRY
1 CALL SETCLR ('BLUE')
RETURN
2 CALL DASH
CALL SETCLR ('RED')
RETURN
END

```

6.2 Injector to Producer Cross-Section Temperature Profiles

C

C

C

The following DISSPLA program is used to generate a temperature profile through a cross-section of the model from the injection well to the production well.

```

LOGICAL *1 FREE (1) /*'/
DIMENSION ZMAT (7,7)
DIMENSION IPAK (400)
COMMON WORK (20000)
CALL DSPDEV ('PLOTTER')
CALL PAGE (11.,8.5)
CALL PHYSOR (1.8,2)
CALL AREA2D (7.5,4.)
CALL FRAME
CALL DUPLX
CALL BASALF ('L/CSTD')
CALL MIXALF ('STANDARD')
CALL XNAME ('(D)ISTANCE, INCHES$',100)
CALL YNAME ('(V)ERT. (S)CALE = 10X (H)OR. (S)CALES$',100)
CALL HEADIN ('(F)IGURE 3: (R)UN 74 (T)EMP (P)ROFILES$',
+100,1.0,4)
CALL HEADIN ('(I)NJECTOR TO (P)RODUCER (C)ROSS-(S)ECTIONS$',
+100,-1.0,4)
CALL HEADIN ('0.75 (P)ORE (V)OLUMES (I)NJECTED$',
+100,0.8,4)
CALL HEADIN ('$',100,1.2,4)
CALL XINTAX
CALL GRAF (0.,5.,45.,0.,5,2.5)

```

C

C The following commands generate arrows and text material which label the injection
C and production points:
C

```
CALL HEIGHT (0.12)
CALL MESSAG ('(I)NJECTION (W)ELLS', 100,0.0,-0.7)
CALL MESSAG ('(P)RODUCTION (W)ELLS',100,6.2,-0.7)
CALL VECTOR (0.0,-0.5,0.0,-0.25,2201)
CALL VECTOR (7.5,-0.5,7.5,-0.25,2201)
```

C
C The next section of commands read in the data. Note that the X-coordinates were
C measured from the top view temperature profile described in Section 6.1 using an
C Engineers scale. The 1:60 scale was chosen so that the length from the injection
C well to the production well was 46.2 units. Thus, there was no need to modify
C the X-coordinates since the actual model length was 45.2548 inches. In other
C words, 1 unit (on a 1:60 Engineers scale) $\approx$ 1 inch (on the model).
C

C The Z-coordinates are 0.8333 and 1.6667 inches for the lower and upper layer
C of thermocouples, respectively.
C

```
CALL BGNMAT (7,7)
      READ (5,FREE) N
      DO 10 I=1,N
            READ (5,FREE) X,Y,Z
10      CALL GETMAT (X,Y,Z,1,0)
      CALL ENDMAT (ZMAT,0)
```

C
C Contouring routines:
C

```
CALL BCOMON (10000)
CALL CONMAK (ZMAT,7,7,5.)
CALL CONMIN (1.5)
CALL CONDIG (0)
CALL SETCLR ('RED')
CALL CONLIN (0,'SOLID','LABELS',1,10)
CALL RASPLN (0.2)
CALL CONTUR (1,'LABELS','DRAW')
CALL ENDPL (0)
CALL DONEPL
STOP
END
```

6.3 Macro Program

```
1 TAG          1000
2 BANK         1100
3 CPLOT        1200
4 MACPLOT      1300
5 TELPLOT      1400
6 /END
1000 MACRO TAG
1001 >*
1002 >*      The tag macro invokes the Tellagraf program
1003 >*
```

```

1004 $RUN NEW:TELLAGRAF
1005 ENDMACRO
1100 MACRO BANK
1101 >*
1102 >*   The bank macro invokes the Tellabank program
1103 >*
1104 $RUN NEW:TELLABANK
1105 ENDMACRO
1200 MACRO CPLOT
1201 >*
1201 >*   The cplot macro prompts for the Fortran DISSPLA file and a data file for
1203 >*   contouring. It then compiles the DISSPLA program which produces a plot
1204 >*   file in '-plot'. The '-plot' file is then converted to an HPGL plot file for the
1205 >*   HP7475A plotter using the '*plotsee' program. Then, the first line of this
1206 >*   file is deleted so that it can be transferred to the HP7550 or any HP plotters
1207 >*   other than the HP7475A. The resulting file, '-plothp', is then sent to the
1208 >*   IBM PC to the 'C:' drive under the name of the data file.
1209 >*
1210 define dispfile
1211 define datafile
1212     write "ENTER THE NAME OF THE *DISSPLA FILE:"
1213     read dispfile from *source*
1214     write "ENTER THE NAME OF THE DATA FILE:"
1215     read dispfile from *source*
1216 $EDIT {dispfile} V18
1217 IF FILE ("-LOAD#") EXISTS, $EMPTY -LOAD#
1218 IF FILE ("-PLOT") EXISTS, $EMPTY -PLOT
1219 IF FILE ("-PLOTHP") EXISTS, $EMPTY -PLOTHP
1220 $RUN *FORTG SCARDS={dispfile}
1221 IF RUNRC > 0, EXIT
1222 $RUN -LOAD#+*DISSPLA 5={datafile} 9=-PLOT
1223 $RUN *PLOTSEE T=5 PAR=-PLOT HP7475F PAGEFILL RETURN
1224 $EDIT -PLOTHP D1
1225 $CONTROL *MSOURCE* FT BREP MTS -PLOTHP C:{datafile}
1226 >ENDMACRO
1300 MACRO MACPLOT
1301 >*
1301 >*   The macplot macro prompts for the Fortran DISSPLA file and a data file for
1303 >*   contouring. This program is the Macintosh equivalent of the CPLOT (IBM)
1304 >*   macro program which is used to run and transfer the contour plot file
1305 >*   generated from the '*plotsee' program to the HP7550 plotter. The resulting
1306 >*   file, -plothp, is sent to the Macintosh hard drive in the form of a MacWrite
1307 >*   document file which uses the same title as the datafile. To run the program
1308 >*   successfully, one must have MacWrite as well as the corresponding cables.
1309 >*
1310 define dispfile
1311 define datafile
1312     write "ENTER THE NAME OF THE *DISSPLA FILE:"
1313     read dispfile from *source*
1314     write "ENTER THE NAME OF THE DATA FILE:"
1315     read dispfile from *source*
1316 $EDIT {dispfile} V18
1317 IF FILE ("-LOAD#") EXISTS, $EMPTY -LOAD#
1318 IF FILE ("-PLOT") EXISTS, $EMPTY -PLOT

```



```

1319 IF FILE ("-PLOTHP") EXISTS, $EMPTY -PLOTHP
1320 $RUN *FORTG SCARDS={dispfile}
1321 IF RUNRC > 0, EXIT
1322 $RUN -LOAD#+*DISSPLA 5={datafile} 9=-PLOT
1323 $RUN *PLOTSEE T=5 PAR=-PLOT HP7475F PAGEFILL RETURN
1324 $EDIT -PLOTHP D1
1325 $CONTROL *MSOURCE* FT BAPP MTS -PLOTHP {datafile}
1326 >ENDMACRO
1400 MACRO TELPLOT
1401 >*
1401 >* The telplot macro will transfer the compiled tellagraf program resulting
1403 >* from the tag macro to a MacWrite document located in the Macintosh
1404 >* hard drive in order to be sent to a HP plotter.
1405 define tellagrafile
1406 write "ENTER THE NAME OF THE TELLAGRAF FILE TO BE
1407 TRANSFERRED:"
1408 >*
1409 $RUN *PLOTSEE T=5 PAR=-PLOT HP7475F PAGEFILL RETURN
1410 $EDIT -PLOTHP D1
1411 $CONTROL *MSOURCE* FT BAPP MTS -PLOTHP {tellagrafile}
1412 >*
1413 >ENDMACRO

```

6.4 MTS Sigfile

In order to be able to access the Macro file from MTS, it is essential to include the following commands in the MTS sigfile:

```

SET MACROS=OFF
SET MACROS=OFF
SET MACROS=ON
>SET VAR MACLIB(1)="MACLIB"

```

where MACLIB(1) = refers to the macrolibrary file 1 to be called
 MACLIB = the name of the macrolibrary file 1 containing the
 programs to be called and are listed in Section 6.3

7. DATA FILE CONSTRUCTION

7.1 General Procedure

Lotus 1-2-3 is used to analyze the experimental data generated from Labtech Notebook. The following types of data calculations which serve the basis for contour plots are explained in detail in this section:

- 7.2 Pore Volume Injected Calculations
- 7.3 Solvent Slug Calculations based on %PV Injected

- 7.4 Top View Temperature Contour Data File Formulation
 7.5 Injector to Producer Temperature Cross-Section Contour Data File Formulation

7.2 Pore Volume Injected

The objective of this section is to examine the procedure used to calculate the time corresponding to a specified injected pore volume.

Let:

%PV	=	the amount of pore volume injected at a certain time, t
V	=	the pore volume of the bead pack, cc
q	=	total steam injection rate, cc/min
t	=	the time at which %PV pore volume injected is obtained, minutes

Assume: V, q and %PV are given.
 where, %PV is chosen arbitrarily at an interval where a contour plot is desired, such as %PV = 0.75 PV or %PV = 1.50 PV.

Thus, t can be determined:
$$t = \frac{(\%PV) \times (V)}{q}$$

After calculating the time it takes to reach a desired pore volume, simply extract the thermocouple temperature values from Lotus 1-2-3 at that time to obtain the necessary information for the temperature profiles.

Sample Calculation 1:

Given:

%PV	=	0.25
V	=	15150 cc
q	=	230.1 cc/min

Find: t at 0.25 PV steam injected

$$t = \frac{(\%PV) \times V}{q_{\text{total}}} = \frac{(0.25) \times (15150 \text{ cc})}{230.1 \text{ cc/min}} = 16.26 \text{ minutes} \cong 16.5 \text{ min.}$$

The calculated time value is rounded up to the next 0.5 minutes since the data in the steamflood experiments was formatted to record data every 30 seconds.

7.3 Solvent Slug Calculation

In solvent slug calculations, the objective is to determine the time required to inject a specified amount of solvent into the physical model which is measured as a percentage of the total pore volume of the model. The amount of solvent that is required to be injected is calculated using the method described in Section 7.2.

Let: %SPV = the percentage of solvent injected into the pore volume of the model
 V = the pore volume of the bead pack, cc
 q_{solvent} = solvent flow rate, cc/min
 t_{solvent} = the time at which %SPV is injected into the model, min

Assume: %SPV, V and q_{solvent}

Thus, t_{solvent} can be determined:
$$t_{\text{solvent}} = \frac{(\%SPV) \times (V)}{q_{\text{solvent}}}$$

Sample Calculation 2:

Given: V = 15340 cc
 q_{solvent} = 200 cc/min
 %SPV = 10%

Find: t_{solvent} at 10% PV injected

$$t = \frac{(0.10) \times (15340 \text{ cc})}{200 \text{ cc / min}} = 7.67 \text{ minutes} \cong 8.0 \text{ min.}$$

7.4 Top View Data Files

Selected experimental data from Lotus-1-2-3 are transferred to the Michigan Terminal System (MTS) manually. Top view data files are typed in R##.### files in the following format:

thermocouples in

TOP layer of model, I2

x-coordinate of

TOP thermocouples, F6.3

y-coordinate of

TOP thermocouples, F6.3

MEGADAC value as

listed in RUNS D.##, F6.3

thermocouples in

BOTTOM layer of model, I2

x-coordinate of

BOTTOM thermocouples, F6.3

y-coordinate of

BOTTOM thermocouples, F6.3

MEGADAC value as

listed in RUNS D.##, F6.3

1

10

20

Column

N.B: *Do not double space the data.

Sample of Top Profile Data File

18		
32.000	0.0000	103.4
23.63	8.50	50.0
15.75	9.00	38.2
7.50	8.75	2.2
4.00	7.50	2.1
8.125	4.00	1.6
13.125	12.5	13.4
8.438	20.0	2.9
13.305	27.725	2.3
3.75	24.375	3.6
12.125	18.375	11.2
20.000	24.063	6.4
28.063	24.125	4.1
25.125	28.000	3.5
19.250	20.000	11.8
24.625	12.250	15.7
18.750	4.00	13.9
0.000	32.000	4.0
17		
32.000	0.0000	103.4
28.000	7.3750	99.7
20.063	7.563	14.1
12.125	7.188	39.2
13.375	3.750	13.2
8.313	12.0	17.1
13.375	20.313	20.0
8.305	28.0	1.8
4.00	28.00	2.8
7.75	23.5	3.9
15.75	23.5	5.5
28.000	28.00	3.1
19.250	28.00	4.2
25.125	20.000	17.1
18.438	12.125	36.9
24.000	4.000	84.3
0.000	32.000	4.0

7.5 Cross-Section Data Files

Injector to producer temperature cross-section data files are denoted by the format X##.### in MTS and are inputted as follows:

*Total number of
data readings from top
view temperature plot, I2

X-coordinate of top Z-coordinate=1.6667 Temperature contour interval
 thermocouples at contour ALWAYS!! for C, F3.0
 interval, C, F6.3 Top thermocouples

X-coordinate of bottom Z-coordinate=0.8333 Temperature contour interval
 thermocouples at contour ALWAYS!! for C, F3.0
 interval, C, F6.3 Bottom thermocouples

1 10 20 Column
 - - - - - - - - - - - - - - -

where C = n., 65., 60., 55., 50., 45., ..., 10., 5.

= temperature contour interval

* = refers to the total number of readings which have temperature contour intervals that appear on the diagonal line from the injection to production well determined from Figure 2D.

Sample of Cross-Section Data File:

39		
0.5	1.6667	105.0
1.1	1.6667	100.0
1.6	1.6667	95.0
2.1	1.6667	90.0
2.6	1.6667	85.0
3.1	1.6667	80.0
3.6	1.6667	75.0
4.2	1.6667	70.0
4.7	1.6667	65.0
5.2	1.6667	60.0
12.1	1.6667	55.0
13.6	1.6667	50.0
15.3	1.6667	45.0
16.8	1.6667	40.0
18.5	1.6667	35.0
20.2	1.6667	30.0
22.0	1.6667	20.0
32.3	1.6667	15.0
0.3	0.8333	100.0
1.4	0.8333	95.0
2.6	0.8333	90.0
3.8	0.8333	85.0
6.0	0.8333	80.0
7.2	0.8333	75.0

where 39 = total number of data points read from the top view profile; total number of data lines in cross-section data file.

Column1 = 1:60 Eng.Scale reading
 Column2 = depth, Z-coordinate, of J-thermocouple in the model

Column3 = thermocouple temperature contour reading, °C

8.3	0.8333	70.0
9.4	0.8333	65.0
10.7	0.8333	60.0
11.9	0.8333	55.0
13.0	0.8333	50.0
14.2	0.8333	45.0
15.3	0.8333	40.0
16.6	0.8333	35.0
17.8	0.8333	30.0
20.5	0.8333	25.0
24.4	0.8333	20.0
26.8	0.8333	15.0
29.0	0.8333	10.0
32.6	0.8333	5.0

Additional Comments:

- ~ Do not double space the data.
- ~ According to the XSECTION program listed in Section 6.2, an Engineers Scale was chosen such that the diagonal length from the injection to production well is 46.2 inches, which was the closest approximation to the actual model diagonal length of 45.25 inches. By trial and error, the only scale that satisfies this criteria is the 1:60 Engineers Scale. In other words, since $d^2 = (32 \text{ in.})^2 + (32 \text{ in.})^2$, the hypotenuse is therefore, $d = 45.2548 \text{ in.}$ Hence, the best fit scale is the 1:60 scale:
 $d = 46.2 \text{ units} \cong 45.2548 \text{ inches}$
- ~ Figure 2D is a schematic diagram of the physical model shows the method used to determine the correct engineering scale used in the cross-section plots. The coordinates are written as (X, Z) because the Y coordinate is zero for all injector to producer temperature contour plots; that is, since $(X, Y, Z) = (X, 0, Z)$, for simplicity, let $(X, 0, Z) = (X, Z)$.

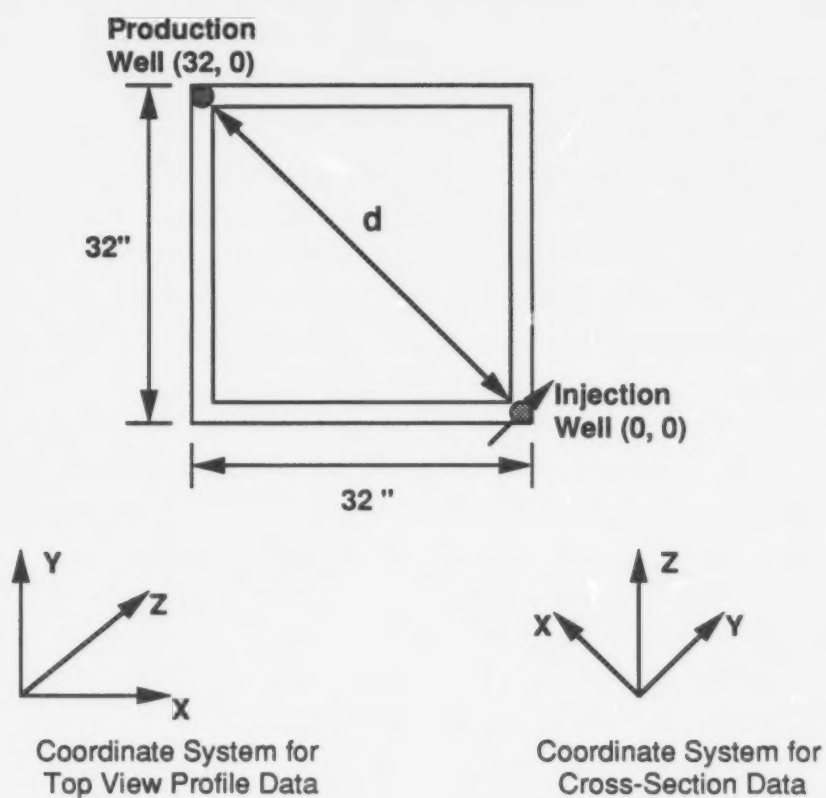


Figure 2D. A Schematic of the Top View of the Aberfeldy Model Showing the Coordinate Systems used for the DISSPLA data files.

Appendix E
List of Suppliers and Materials

Item	Supplier
SIHI Closed Couple Liquid Ring Vacuum Pump (SIHI LRM 10603—1.5 hp close coupled glass filled epoxy resin vacuum pump c/w 208/3/60 teflon motor c/w teflon gaskets)	T.D.H. Fluid Systems Inc. 4634-91 Avenue Edmonton, Alberta, T6B 2L1
Silastic 732 Adhesive Sealant RTV Kimtuff wipers Hammond (plain aluminum) panel	Central Stores Materials Management Department The University of Alberta Edmonton, Alberta T6G 2E1 (403) 492-4246
1/8" Celcite Neoprene™ sponge	Continental Petroleum ((CP) Rubber Inc.) 9725-62 Avenue Edmonton, Alberta T6G 0E5 (403) 437-1260
Faxam-100	McEwen's Esso 3704-92 Avenue Box 8671, Station L Edmonton, Alberta T8C 4J4 (403) 465-0152
Sparkleen Detergent Parafilm M* Laboratory Film Fisherbrand disposable (flint glass) pasteur pipets Kimwipes wipers Fisherbrand mechanical pump fluid Sodium chloride	Fisher Scientific 10720-178 Street Edmonton, Alberta T5S 1J3 (403) 483-2123
DAS-8—8 channel A/D Board EXP-16—16 channel multiplexer C1800—cables LTN-03—Labtech Notebook	Dycor Industrial Research Ltd. #130, 17303-102 Street Edmonton, Alberta T5S 1J8 (403) 486-0091
Fluke-83 Multimeter	Cardinal Industrial Electronics 10630-172 Street Edmonton, Alberta T5S 1H8 (403)483-6266
0.3 mm fibre plotter pens for the HP plotter (for plotter paper) Graphics plotter paper	Northwest Digital 10640-170 Street Edmonton, Alberta T5S 1P3 (403) 486-3598

Item	Supplier
Industrial glass beads (3 mm diam. (6-8 U.S. mesh) technical quality solid glass spheres)	Rotair Industries 1040-78 Avenue Edmonton, Alberta T6P 1L7 (403) 440-2775
Walk-in cooler/freezer	Edmonton Refrigeration Ltd. 14203-128A Avenue Edmonton, Alberta T5L 4P5 (403) 454-3000
36"x36"x8.5" granite block	DoAll Edmonton Ltd. 9743-45 Avenue Edmonton, Alberta T6E 5V8 (403) 436-0373
Fibreglass tray	Triple M Fibreglass Ltd. 8135 Wagner Road Edmonton, Alberta T6E 4N6 (403) 465-0726
1.5" vacuum traps 1.5" polyethylene trap jar	Tri "S" Dairy Equipment Ltd. 14804-119 Avenue Edmonton, Alberta T5L 2M6
2—4207951506 bushings 2—4207721150 nipples 2—4207721142 nipples 2—4207721130 nipples 4—4206690010 elbows 2—4206900010 female adaptor 2—7436265010 Hayward 1" 3-way ball valve 4—4207500010 hose adaptor	Scepter Manufacturing Co. Ltd. 4225-92 Avenue Edmonton, Alberta T6B 3M7 (403) 468-4444
Slik No.5 medium-duty degreaser (originator: Baroid of Canada Ltd, Calgary, Alberta, (403) 263-8740)	NL Treating Chemicals 1500, 840-7th Avenue S.W. Calgary, Alberta T2P 3G2 (403) 263-8740
Swagelok fittings	Edmonton Valve and Fitting Ltd. 4503-93 Street Edmonton, Alberta T6E 5S9

Item	Supplier
A11-16-J-GSS-15" (miniature quick disconnect small diameter thermocouple, type J316SS sheath)	Alltemp Sensors Inc. 9245-34A Avenue
A11-16-J-USS-6" (miniature miniplug type J thermocouple, ungrounded junction)	Edmonton, Alberta T6E 5T6 (403) 463-7035
1237-6-J—connectors mini stripanel (for J-type thermocouples)	
1210-J—mini jack connector	
1260-J—mini plug connector	
640-JX-PC-PC20 (J-thermocouple wire)	

Appendices Part II: High Pressure Model

APPENDIX F

Initial and Boundary conditions for reservoir flow

F.1 Initial conditions

$$S_o(r, \theta, z, t = 0) = S_{oi}$$

$$S_w(r, \theta, z, t = 0) = S_{wi}$$

$$P_o(r, \theta, z, t = 0) = P_{oi}$$

$$T(r, \theta, z, t = 0) = T_i$$

F.2 Boundary conditions

F.2.1 Outer boundaries

F.2.1.1 No fluid flow across top&bottom of reservoir, ($r = \pm H/2$)

$$\begin{aligned} \frac{kk_{ro}}{\mu_o} \cdot \left(\frac{\partial P_o}{\partial r} - \frac{\rho_o g \delta(r \sin \theta)}{\partial r} \right) &= 0 \\ \frac{kk_{rw}}{\mu_w} \cdot \left(\frac{\partial P_w}{\partial r} - \frac{\rho_w g \delta(r \sin \theta)}{\partial r} \right) &= 0 \\ \frac{kk_{rg}}{\mu_g} \cdot \left(\frac{\partial P_g}{\partial r} - \frac{\rho_g g \delta(r \sin \theta)}{\partial r} \right) &= 0 \end{aligned}$$

F.2.1.2 No fluid flow across the end boundaries of the pattern, ($z = 0, L$)

$$\begin{aligned} \frac{kk_{ro}}{\mu_o} \cdot \frac{\partial P_o}{\partial z} &= 0 \\ \frac{kk_{rw}}{\mu_w} \cdot \frac{\partial P_w}{\partial z} &= 0 \\ \frac{kk_{rg}}{\mu_g} \cdot \frac{\partial P_g}{\partial z} &= 0 \end{aligned}$$

F.2.1.3 No heat loss to overburden and surrounding formations

$$\frac{1}{r} \frac{\partial}{\partial r} \left(\frac{r K_{hob} \delta T_{ob}}{\partial r} \right) + \frac{1}{r^2} \frac{\partial}{\partial \theta} \left(\frac{K_{ob} \delta T_{ob}}{\partial \theta} \right) + \frac{\partial}{\partial z} \left(\frac{K_{ob} \delta T_{ob}}{\partial z} \right) + q_L^* = \rho_{ob} C_{ob} \frac{\delta T_{ob}}{\partial t}$$

F.2.2 Inner boundaries

F.2.2.1 Fluids production at the production well

$$\begin{aligned} q_o^* &= - \frac{\rho_o A k k_{ro}}{V_b \mu_o} \cdot \frac{\partial P_o}{\partial r} \\ q_w^* &= - \frac{\rho_w A k k_{rw}}{V_b \mu_w} \cdot \frac{\partial P_w}{\partial r} \\ q_g^* &= - \frac{\rho_g A k k_{rg}}{V_b \mu_g} \cdot \frac{\partial P_g}{\partial r} \end{aligned}$$

Therefore,

$$q_g^* = q_o^* \frac{\rho_g k_{rg} \mu_o}{\rho_o k_{ro} \mu_g}$$

$$q_g^* = q_o^* \frac{\rho_g k_{rg} \mu_o}{\rho_o k_{ro} \mu_g}$$

F.2.2.2 Heat production at the production well

$$q_{hprod}^* = h_{oprod}^* q_{oprod}^* + h_{uprod}^* q_{uprod}^* + h_{sprod}^* C_{guprod}^* q_{gprod}^* + h_{aprod}^* C_{gasprod}^* q_{gprod}^*$$

F.2.2.3 Mass injection rate of water at the injection well

$$W_{uw} = \int_{Ainj} \frac{\rho_w k k_{rw}}{\mu_w} \cdot (\nabla P_w + \rho_w g \nabla r) dA$$

F.2.2.4 Mass injection rate of steam and additive in the vapour phase

$$W_{gw} + W_{ga} = \int_{Ainj} \frac{\rho_g k k_{rg}}{\mu_g} \cdot (\nabla P_g + \rho_g g \nabla r) dA$$

F.2.2.5 Heat injection rate at the steam injection well

$$W_{ga} h_{ga} + W_{gw} h_{gw} + W_{uw} h_{uw} =$$

$$\int_{Ainj} \left[K_{hr} \nabla T + \frac{\rho_g h_g k k_{rg}}{\mu_g} \cdot (\nabla P_g + \rho_g g \nabla r) + \frac{\rho_w h_w k k_{rw}}{\mu_w} \cdot (\nabla P_w + \rho_w g \nabla r) \right] dA$$

APPENDIX G

Equations written in terms of $M_D = M / M_R$

Water mass balance

$$\begin{aligned}
& \left[\frac{\phi_R S_{wR} \rho_{wR}}{t_R} \right] \frac{\partial}{\partial t_D} (\phi_D S_{wD} \rho_{wD}) \\
& + \left[\frac{\phi_R S_{gR} \rho_{gR} C_{gR}}{t_R} \right] \frac{\partial}{\partial t_D} (\phi_D S_{gD} \rho_{gD} C_{gD}) = \\
& \left[\frac{\rho_{wR} k k_{r,wR} P_{wR}}{r_R^2 \mu_{wR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{wD} k k_{r,wD}}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR} C_{gR} k k_{r,gR} P_{gR}}{r_R^2 \mu_{gR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD} C_{gD} k k_{r,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{wR}^2 k k_{r,wR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{wR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{wD}^2 k k_{r,wD} g_D}{\mu_{wD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& - \left[\frac{\rho_{gR}^2 C_{gR} k k_{r,gR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{gR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD}^2 C_{gD} k k_{r,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{wR} k k_{r,wR} P_{wR}}{r_R^2 \theta_R^2 \mu_{wR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{wD} k k_{r,wD}}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{gR} C_{gR} k k_{r,gR} P_{gR}}{r_R^2 \theta_R^2 \mu_{gR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD} C_{gD} k k_{r,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{wR}^2 k k_{r,wR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{wR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{wD}^2 k k_{r,wD} g_D}{\mu_{wD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{gR}^2 C_{gR} k k_{r,gR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{gR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD}^2 C_{gD} k k_{r,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{wR} k k_{r,wR} P_{wR}}{z_R^2 \mu_{wR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{wD}^2 k k_{r,wD} g_D}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{gR} C_{gR} k k_{r,gR} P_{gR}}{z_R^2 \mu_{gR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{gD}^2 C_{gD} k k_{r,gD} g_D}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial z_D} \right) \\
& + \dot{q}_{wR} \dot{q}_{wD} + C_{gR} \dot{q}_{gR} C_{gD} \dot{q}_{gD}
\end{aligned} \tag{G-1}$$

Steam-additive mass balance

$$\begin{aligned}
& \left[\frac{\phi_R S_{oR} \rho_{oR} C_{oR}}{t_R} \right] \frac{\partial}{\partial t_D} (\phi_D S_{oD} \rho_{oD} C_{oD}) \\
& + \left[\frac{\phi_R S_{gR} \rho_{gR} C_{gR}}{t_R} \right] \frac{\partial}{\partial t_D} (\phi_D S_{gD} \rho_{gD} C_{gD}) = \\
& \left[\frac{\rho_{oR} C_{oR} k k_{r,oR} P_{oR}}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD} C_{oD} k k_{r,oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR} C_{gR} k k_{r,gR} P_{gR}}{r_R^2 \mu_{gR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD} C_{gD} k k_{r,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial r_D} \right)
\end{aligned}$$

$$\begin{aligned}
& - \left[\frac{\rho_{oR} C_{oR} k k_{oR} g_R r_R \sin \theta_R}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD}^2 C_{oD} k k_{oD} g_D}{\mu_{oD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& - \left[\frac{\rho_{iR} C_{iR} k k_{iR} g_R r_R \sin \theta_R}{r_R^2 \mu_{iR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{iD}^2 C_{iD} k k_{iD} g_D}{\mu_{iD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{oR} C_{oR} k k_{oR} P_{oR}}{r_R^2 \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD} C_{oD} k k_{oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{iR} C_{iR} k k_{iR} P_{iR}}{r_R^2 \theta_R^2 \mu_{iR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{iD} C_{iD} k k_{iD}}{\mu_{iD}} \cdot \frac{\partial P_{iD}}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{oR}^2 C_{oR} k k_{oR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD}^2 C_{oD} k k_{oD} g_D}{\mu_{oD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{iR}^2 C_{iR} k k_{iR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{iR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{iD}^2 C_{iD} k k_{iD} g_D}{\mu_{iD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{oR} C_{oR} k k_{oR} P_{oR}}{z_R^2 \mu_{oR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{oD}^2 C_{oD} k k_{oD} g_D}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{iR} C_{iR} k k_{iR} P_{iR}}{z_R^2 \mu_{iR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{iD}^2 C_{iD} k k_{iD} g_D}{\mu_{iD}} \cdot \frac{\partial P_{iD}}{\partial z_D} \right) \\
& + C_{oR}^* q_{oR}^* C_{oD}^* q_{oD}^* + C_{iR}^* q_{iR}^* C_{iD}^* q_{iD}^*
\end{aligned} \tag{G-2}$$

Energy balance

$$\begin{aligned}
& \left[\frac{(1 - \phi_R) \rho_{rR} U_{rR}}{t_R} \right] \frac{\partial}{\partial t_D} \left((1 - \phi_D) \rho_{rD} U_{rD} \right) \\
& + \left[\frac{\phi_R S_{oR} \rho_{oR} U_{oR}}{t_R} \right] \frac{\partial}{\partial t_D} \left(\phi_D S_{oD} \rho_{oD} U_{oD} \right) \\
& + \left[\frac{\phi_R S_{uR} \rho_{uR} U_{uR}}{t_R} \right] \frac{\partial}{\partial t_D} \left(\phi_D S_{uD} \rho_{uD} U_{uD} \right) \\
& + \left[\frac{\phi_R S_{iR} \rho_{iR} U_{iR}}{t_R} \right] \frac{\partial}{\partial t_D} \left(\phi_D S_{iD} \rho_{iD} U_{iD} \right) = \\
& \left[\frac{K_{h,rR} T_R}{r_R^2} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D K_{h,rD} \cdot \partial T_D}{\partial r_D} \right) \\
& + \left[\frac{K_{h,rR} T_R}{r_R^2 \theta_R^2} \right] \frac{\partial}{\partial \theta_D} \left(\frac{K_{h,rD} \partial T_D}{\partial \theta_D} \right) \\
& + \left[\frac{K_{h,rR} T_R}{z_R^2} \right] \frac{\partial}{\partial z_D} \left(\frac{K_{h,rD} \partial T_D}{\partial z_D} \right) \\
& + \left[\frac{\rho_{oR} h_{oR} k k_{oR} P_{oR}}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD} h_{oD} k k_{oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{oR}^2 h_{oR} k k_{oR} g_R r_R \sin \theta_R}{r_R^2 \mu_{oR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD}^2 h_{oD} k k_{oD} g_D}{\mu_{oD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{oR} h_{oR} k k_{oR} P_{oR}}{r_R^2 \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD} h_{oD} k k_{oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{oR}^2 h_{oR} k k_{oR} g_R r_R \sin \theta_R}{r_R \theta_R^2 \mu_{oR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{oD}^2 h_{oD} k k_{oD} g_D}{\mu_{oD}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{oR} h_{oR} k k_{oR} P_{oR}}{z_R^2 \mu_{oR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{oD} h_{oD} k k_{oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial z_D} \right)
\end{aligned}$$

$$\begin{aligned}
& + \left[\frac{\rho_{uR} h_{uR} k k_{t,uR} P_{uR}}{r_R^2 \mu_{uR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{uD} h_{uD} k k_{t,uD}}{\mu_{uD}} \cdot \frac{\partial P_{uD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{uR}^2 h_{uR} k k_{t,uR} g_R r_R \sin \theta_R}{r_R^2 \mu_{uR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{uD}^2 h_{uD} k k_{t,uD} g_D}{\mu_{uD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{uR} h_{uR} k k_{t,uR} P_{uR}}{r_R^2 \theta_R^2 \mu_{uR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{uD} h_{uD} k k_{t,uD}}{\mu_{uD}} \cdot \frac{\partial P_{uD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{uR}^2 h_{uR} k k_{t,uR} g_R r_R \sin \theta_R}{r_R^2 \theta_R^2 \mu_{uR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{uD}^2 h_{uD} k k_{t,uD} g_D}{\mu_{uD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{uR} h_{uR} k k_{t,uR} P_{uR}}{z_R^2 \mu_{uR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{uD} h_{uD} k k_{t,uD}}{\mu_{uD}} \cdot \frac{\partial P_{uD}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{gR} h_{gR} k k_{t,gR} P_{gR}}{r_R^2 \mu_{gR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD} h_{gD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR}^2 h_{gR} k k_{t,gR} g_R r_R \sin \theta_R}{r_R^2 \mu_{gR}} \right] \frac{1}{r_D} \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD}^2 h_{gD} k k_{t,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR} h_{gR} k k_{t,gR} P_{gR}}{r_R^2 \theta_R^2 \mu_{gR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD} h_{gD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{gR}^2 h_{gR} k k_{t,gR} g_R r_R \sin \theta_R}{r_R^2 \theta_R^2 \mu_{gR}} \right] \frac{1}{r_D^2} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD}^2 h_{gD} k k_{t,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{gR} h_{gR} k k_{t,gR} P_{gR}}{z_R^2 \mu_{gR}} \right] \frac{\partial}{\partial z_D} \left(\frac{\rho_{gD} h_{gD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial z_D} \right)
\end{aligned}$$

(G-3)

APPENDIX H

Dimensionless conservation equations

Water mass balance

$$\begin{aligned}
& \left[\frac{\phi_R S_{wR} r_R^2 \mu_{wR}}{k k_{t,wR} P_{wR} t_R} \right] r_D \frac{\partial}{\partial t_D} (\phi_D S_{wD} \rho_{wD}) \\
& \left[\frac{\phi_R S_{gR} r_R^2 \mu_{wR} C_{g,wR} \rho_{gR}}{k k_{t,wR} P_{wR} \rho_{wR} t_R} \right] r_D \frac{\partial}{\partial t_D} (\phi_D S_{gD} \rho_{gD} C_{g,wD}) = \\
& \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{wD} k k_{t,wD}}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR} C_{g,wR} k_{t,gR} \mu_{wR} P_{gR}}{\rho_{wR} k_{t,wR} \mu_{gR} P_{wR}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD} C_{g,wD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{wR} g_R r_R \sin \theta_R}{P_{wR}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{wD}^2 k k_{t,wD} g_D}{\mu_{wD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& - \left[\frac{\rho_{gR}^2 C_{g,wR} k_{t,gR} \mu_{wR} g_R r_R \sin \theta_R}{\rho_{wR} k_{t,wR} \mu_{gR} P_{wR}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD}^2 C_{g,wD} k k_{t,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{1}{\theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{wD} k k_{t,wD}}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{gR} C_{g,wR} k_{t,gR} \mu_{wR} P_{gR}}{\rho_{wR} k_{t,wR} \mu_{gR} P_{wR} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD} C_{g,wD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial \theta_D} \right) \\
& - \left[\frac{r_R^2 \rho_{wR} g_R \sin \theta_R}{\theta_R^2 P_{wR}} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{wD}^2 k k_{t,wD} g_D}{\mu_{wD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{gR}^2 C_{g,wR} k_{t,gR} \mu_{wR} g_R r_R^2 \sin \theta_R}{\rho_{wR} k_{t,wR} \mu_{gR} P_{wR} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{gD}^2 C_{g,wD} k k_{t,gD} g_D}{\mu_{gD}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{r_R^2}{z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{wD} k k_{t,wD}}{\mu_{wD}} \cdot \frac{\partial P_{wD}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{gR} C_{g,wR} k_{t,gR} \mu_{wR} P_{gR} r_R^2}{\rho_{wR} k_{t,wR} \mu_{gR} P_{wR} z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{gD}^2 C_{g,wD} k k_{t,gD} g_D}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial z_D} \right) \\
& + \left[\frac{q_{wR} r_R^2 \mu_{wR}}{\rho_{wR} k k_{t,wR} P_{wR}} \right] r_D q_{wD} + \left[\frac{C_{g,wR} q_{gR} r_R^2 \mu_{wR}}{\rho_{wR} k k_{t,wR} P_{wR}} \right] r_D C_{g,wD} q_{gD}
\end{aligned} \tag{H-1}$$

Steam-additive mass balance

$$\begin{aligned}
& \left[\frac{\phi_R S_{oR} r_R^2 \mu_{oR}}{k k_{t,oR} P_{oR} t_R} \right] r_D \frac{\partial}{\partial t_D} (\phi_D S_{oD} \rho_{oD} C_{o,wD}) \\
& + \left[\frac{\phi_R S_{gR} r_R^2 \mu_{oR} \rho_{gR} C_{g,oR}}{k k_{t,oR} P_{oR} \rho_{oR} t_R C_{o,wR}} \right] r_D \frac{\partial}{\partial t_D} (\phi_D S_{gD} \rho_{gD} C_{g,oD}) = \\
& \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{oD} C_{o,wD} k k_{t,oD}}{\mu_{oD}} \cdot \frac{\partial P_{oD}}{\partial r_D} \right) \\
& + \left[\frac{\rho_{gR} C_{g,oR} k_{t,gR} \mu_{oR} P_{gR}}{\rho_{oR} C_{o,wR} k_{t,oR} \mu_{gR} P_{oR}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{gD} C_{g,oD} k k_{t,gD}}{\mu_{gD}} \cdot \frac{\partial P_{gD}}{\partial r_D} \right)
\end{aligned}$$

$$\begin{aligned}
& - \left[\frac{\rho_{0R} g_R r_R \sin \theta_R}{P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D}^2 C_{00D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& - \left[\frac{\rho_{0R}^2 C_{00R} k_{0R} \mu_{0R} g_R r_R \sin \theta_R}{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D}^2 C_{00D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{1}{\theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D} C_{00D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R}}{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D} C_{00D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial \theta_D} \right) \\
& - \left[\frac{r_R^2 \rho_{0R} g_R \sin \theta_R}{\theta_R^2 P_{0R}} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D}^2 C_{00D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{0R}^2 C_{00R} k_{0R} \mu_{0R} g_R r_R^2 \sin \theta_R}{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D}^2 C_{00D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{r_R^2}{z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{0D} C_{00D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R} r_R^2}{\rho_{0R} C_{00R} k_{0R} \mu_{0R} P_{0R} z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{0D} C_{00D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial z_D} \right) \\
& + \left[\frac{C_{00R}^* q_{0R}^* r_R^2 \mu_{0R}}{C_{00R} \rho_{0R} k_{0R} P_{0R}} \right] r_D C_{00D}^* q_{0D}^* + \left[\frac{C_{00R}^* q_{0R}^* r_R^2 \mu_{0R}}{C_{00R} \rho_{0R} k_{0R} P_{0R}} \right] r_D C_{00D}^* q_{0D}^* \quad (H-2)
\end{aligned}$$

Energy balance

$$\begin{aligned}
& \left[\frac{(1 - \phi_R) \rho_{0R} U_{0R} r_R^2 \mu_{0R}}{\rho_{0R} k k_{0R} h_{0R} P_{0R} t_R} \right] r_D \frac{\partial}{\partial t_D} \left((1 - \phi_D) \rho_{0D} U_{0D} \right) \\
& + \left[\frac{\phi_R S_{0R} r_R^2 \mu_{0R} U_{0R}}{k k_{0R} h_{0R} P_{0R} t_R} \right] r_D \frac{\partial}{\partial t_D} \left(\phi_D S_{0D} \rho_{0D} U_{0D} \right) \\
& + \left[\frac{\phi_R S_{0R} r_R^2 \mu_{0R} U_{0R} \rho_{0R}}{k k_{0R} h_{0R} P_{0R} t_R \rho_{0R}} \right] r_D \frac{\partial}{\partial t_D} \left(\phi_D S_{0D} \rho_{0D} U_{0D} \right) \\
& + \left[\frac{\phi_R S_{0R} r_R^2 \mu_{0R} U_{0R} \rho_{0R}}{k k_{0R} h_{0R} P_{0R} t_R \rho_{0R}} \right] r_D \frac{\partial}{\partial t_D} \left(\phi_D S_{0D} \rho_{0D} U_{0D} \right) = \\
& \left[\frac{K_{h,R} T_R \mu_{0R}}{\rho_{0R} k k_{0R} h_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D K_{h,D} \cdot \partial T_D}{\partial r_D} \right) \\
& + \left[\frac{K_{h,R} T_R \mu_{0R}}{\rho_{0R} k k_{0R} h_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{K_{h,D} \partial T_D}{\partial \theta_D} \right) \\
& + \left[\frac{K_{h,R} T_R \mu_{0R} r_R^2}{\rho_{0R} k k_{0R} h_{0R} P_{0R} z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{K_{h,D} \partial T_D}{\partial z_D} \right) \\
& + \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D} h_{0D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{0R} g_R r_R \sin \theta_R}{P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D}^2 h_{0D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{1}{\theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D} h_{0D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial \theta_D} \right) \\
& - \left[\frac{r_R^2 \rho_{0R} g_R \sin \theta_R}{\theta_R^2 P_{0R}} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D}^2 h_{0D} k k_{0D} g_D}{\mu_{0D}} \cdot \frac{\partial(r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{r_R^2}{z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{0D} h_{0D} k k_{0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial z_D} \right)
\end{aligned}$$

$$\begin{aligned}
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{0R}^2 h_{0R} k_{\tau 0R} \mu_{0R} g_R r_R \sin \theta_R}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D}^2 h_{0D} k_{\tau 0D} g_D}{\mu_{0D}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{0R}^2 h_{0R} k_{\tau 0R} \mu_{0R} g_R r_R^2 \sin \theta_R}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D}^2 h_{0D} k_{\tau 0D} g_D}{\mu_{0D}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} r_R^2}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial z_D} \right) \\
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial r_D} \right) \\
& - \left[\frac{\rho_{0R}^2 h_{0R} k_{\tau 0R} \mu_{0R} g_R r_R \sin \theta_R}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}} \right] \frac{\partial}{\partial r_D} \left(\frac{r_D \rho_{0D}^2 h_{0D} k_{\tau 0D} g_D}{\mu_{0D}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial r_D} \right) \\
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R}}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial \theta_D} \right) \\
& - \left[\frac{\rho_{0R}^2 h_{0R} k_{\tau 0R} \mu_{0R} g_R r_R^2 \sin \theta_R}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} \theta_R^2} \right] \frac{1}{r_D} \frac{\partial}{\partial \theta_D} \left(\frac{\rho_{0D}^2 h_{0D} k_{\tau 0D} g_D}{\mu_{0D}} \cdot \frac{\partial (r_D \sin \theta_D)}{\partial \theta_D} \right) \\
& + \left[\frac{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} r_R^2}{\rho_{0R} h_{0R} k_{\tau 0R} \mu_{0R} P_{0R} z_R^2} \right] r_D \frac{\partial}{\partial z_D} \left(\frac{\rho_{0D} h_{0D} k_{\tau 0D}}{\mu_{0D}} \cdot \frac{\partial P_{0D}}{\partial z_D} \right) \\
& + \left[\frac{q_{0R}^2 r_R^2 \mu_{0R}}{\rho_{0R} k_{\tau 0R} h_{0R} P_{0R}} \right] r_D q_{0D} - \left[\frac{q_{0R}^2 r_R^2 \mu_{0R}}{\rho_{0R} k_{\tau 0R} h_{0R} P_{0R}} \right] r_D q_{0D}
\end{aligned}$$

(H-3)

Appendix I
Papers Presented

THIS IS A PREPRINT — SUBJECT TO CORRECTION

EFFECT OF BOTTOM AND TOP WATER ON CYCLIC STEAM STIMULATION RESPONSE

By

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BP Resources Canada Ltd**PUBLICATION RIGHTS RESERVED**

THIS PAPER IS TO BE PRESENTED AT THE 39th ANNUAL TECHNICAL MEETING OF THE PETROLEUM SOCIETY OF CIM HELD IN CALGARY, JUNE 12 - 16, 1988. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE TECHNICAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

In many heavy oil reservoirs in Alberta and Saskatchewan, a high water saturation zone occurs below or above the oil zone. Such water zones can take a number of forms, and in special circumstances can even be beneficial. However, in most cases, they cause channelling in steam injection operations, leading to low oil-steam ratios. This paper considers cyclic steam stimulation in particular, in the presence of high water saturation zones. The results are based upon simulation studies for Lloydminster and Cold Lake reservoirs.

It is shown that cyclic steam stimulation response depends strongly on: water-oil zone thickness and permeability ratios, vertical permeability, oil viscosity, steam injection rate and steam injection interval. Partial penetration is one of the options that can help. For a given set of circumstances, operation may still be viable in the presence of a communicating water zone. Top water is likely to be more undesirable than bottom water.

INTRODUCTION

Communicating water zones are a frequent occurrence in the heavy oil formations of Alberta, Saskatchewan, California, and other areas. Most of the time, such zones occur below the oil zone. In some cases, in Athabasca, Cold Lake, and California, they lie above the oil zone. A water zone can take a number of forms: it can be a transition zone, it can be a low oil saturation zone, or it can be a 100% water zone, or even an aquifer. Frequently, the mineralogy of the high water saturation zone differs considerably from that of the oil zone. Local geology and well log interpretations are important for assessing the effect of communicating water zones on cyclic steam stimulation response. In particular, the formation description derived from well logs is of great value in cyclic steaming formations with contiguous water zones. This paper presents selected results of a simulation study to examine the effect of communicating high water saturation zones adjacent to an oil-bearing formation.

SIMULATION DETAILS

Reservoirs

The reservoirs considered in this study were a typical Lloydminster formation (typified by the Aberfeldy reservoir) and a typical Cold Lake formation. Relevant data for the simulations is given in Table 1; Figs. 1 and 2 give the oil-water and oil-gas relative permeability curves used in the simulations. The oil viscosity-temperature curves are shown in Figs. 3 and 4, for the Aberfeldy and Cold Lake formations, respectively.

Simulator Used and Other Details

A three-phase, three-dimensional fully implicit steam-water-oil simulator was developed for this work. It treats oil as a single non-volatile component. The grid used consisted of $5 \times 5 \times 2$ or $5 \times 5 \times 3$ blocks, representing a quadrant for single well stimulations discussed here. A typical complete run (three cycles, each consisting of 30 days of injection, 5 days of soak, and 90 days of production) took 200 to 700 seconds (CPU) of Amdahl 8080 time. The material and heat balance errors were well below 0.1%.

A factor that can influence simulation results is the well production control. In the present work, a productivity index of 10 was employed with a minimum bottomhole pressure limit.

In Cold Lake, under conditions where no bottom water is present, steam injection is feasible only under parting pressures. This is an important factor, yet it is difficult to simulate. In the present runs, formation parting was not considered. While it is a good assumption for Aberfeldy type reservoirs, it is rather tenuous for Cold Lake formations, where bottom water is absent, and the water saturation is not mobile.

SIMULATION RESULTS

Cyclic Steaming Runs for Aberfeldy

The variables examined in the case of a typical (except for thickness) Lloydminster formation were: steam slug size, bottom water thickness for a given oil zone thickness (36 ft), injection interval, and vertical permeability. A partially penetrating well was also considered. Many other variables influence cyclic steaming performance, including steam pressure, steam injection rate, quality, soak time, injection/production intervals, well operating conditions, spacing, interference with other wells,

increasing/decreasing/constant slug sizes for consecutive cycles, steam additives, and formation parting. Tables 2(a) and (b) summarize the principal results of cyclic steam stimulation simulations conducted. The run termination criterion was a preset (200 sec) computer time. Only in a few instances runs as long as 700 sec were conducted.

Figure 5 shows the oil and water production curves for Run ABC3, being a typical example of the results obtained. In this case, the steam slug is decreased from cycle to cycle, and the overall oil-steam ratio is 0.125. Figure 6 shows the water-oil ratio, with a steady increase over the three cycles.

Tables 2(a) and (b) show three groups of results: the first run in each group employs a constant steam slug in each cycle, the second run employs increasing slugs from cycle to cycle, and the third run employs decreasing slugs from cycle to cycle. The fourth run in the first group (ABC4) employs longer soak times following steam injection. It is seen that the oil-steam ratio is highest - about 0.15 - in the first cycle. In subsequent cycles it drops because of water saturation buildup. This is to be expected because the formation thickness is small, so that gravity flow is restricted. Furthermore, after the first cycle, the inflow of cold oil from the cooler parts of the formation is limited by the high oil viscosity. This is evidenced by the high water-oil ratio values in the first cycle, and in most cases in the second and third cycles. At the end of steam injection, the water saturation around the wellbore is very high, causing the very high water-oil ratios. The performance of Run ABC3 is most favourable in the group, with steam slugs decreasing: 18, 12, and 6 MBbls in the three cycles. The corresponding oil-steam ratios are 0.15, 0.13, and 0.12, respectively. In Run ABC2 the oil-steam ratios are lower, for the larger steam slugs used. A long soak time (20 days in Run ABC4) has a similar undesirable effect, leading to a drop in the oil-steam ratio, possibly due to cooling of the oil around the wellbore. On the basis of these limited results, it may be speculated that decreasing steam slugs in the second cycle are desirable, but the amount of decrease is a factor to be considered, and that long soak times cause a drop in the oil-steam ratio.

Effect of Bottom Water

The Aberfeldy runs discussed above were repeated for a bottom water zone (Runs ABC6, ABC8, ABC9, ABC11, ABC17, ABC18, Tables 2(a) and (b)), the bottom water thickness being 0.1 and 0.5 of the oil zone thickness, as indicated in Table 2(b).

It is obvious that the performance is poorer than in the absence of bottom water (Runs ABC1 to 4). The oil-steam ratio is seen to be nearly one-half, or less, of that in the absence of bottom water. Typical oil/water production curves and water-oil ratios are shown in Figs. 7 and 8 for Run ABC8. The water-oil ratios are much higher - two to three times those in the absence of water. Much higher water-oil ratios occur in the thicker bottom water case. Figure 7 shows the curves for Run ABC11. Here the water-oil ratio is 200-400 in the second cycle. The larger steam slug in the second cycle (36 MBbls vs. 18 MBbls in the first cycle) further aggravates the situation. This tendency was also observed in Runs ABC6 and ABC8, where the water-oil ratio in the second cycle is higher when a larger volume of steam is injected. It is unclear as to why the water-oil ratio in the second cycle of Run ABC8 is lower than that in the first cycle of the same run, although considerably more steam was injected in the second cycle. It is the result of complex interaction of the limited bottom water, conductive heating, and relative mobility/temperature relationships. The oil-steam ratio in the third cycle shows an improvement, because the conductive heating from the water layer to the oil layer above is starting to take effect.

Based upon the above, it may be said that generally speaking, bottom water is undesirable in cyclic steaming, particularly when the bottom water thickness is large. Increasing steam slugs from cycle to cycle may have limited benefits, but it is more likely to give poorer performance than a constant slug. In fact, there may be some merit in reducing the steam slug size when bottom water is present. In all cases simulated, the oil-steam ratio was well below the minimum acceptable value of 0.1.

Cyclic Steaming Runs for Cold Lake

A number of steam stimulation simulations were carried out for the Cold Lake Clearwater formation. It should be reiterated that in Cold Lake, when a high water saturation does not occur, steam injection is possible under parting pressures only. This was not simulated in the present study. As a result, the case of no bottom water does not reflect the field experience under parting conditions. The oil-steam ratio in this case was 0.0147 for conditions similar to those considered for the Aberfeldy formation. Formation heating was relatively uniform, with a higher steam saturation in the upper part of the formation. The terminal oil production rate was only 0.5 B/D, compared to 162 B/D for water. Steam parting, not considered in these simulations, helps to spread most of the steam away from the wellbore, while in the present case water saturation builds up

near the wellbore. The oil production rate increased in subsequent cycles in view of continued conduction heating of the oil.

In the case of a bottom water layer 3.6 ft thick (oil zone is 36 ft thick), the oil-steam ratio was 0.0001, showing that even relatively thin water sands have an adverse effect on performance. For a thicker water zone (36 ft), the oil-steam ratio was 0.001.

The above results show, first, that the cyclic steaming performance simulation for Cold Lake, where steam parting is commonly present, cannot be realistically simulated by a non-frac simulator, and secondly, even small amounts of bottom water are likely to lower steam stimulation performance greatly even for a very high viscosity oil.

Steam Injection Using Partial Penetration

When bottom water is present, there may be some merit in completing stimulation wells partially into the formation. In classical reservoir engineering, partial penetration has been considered for special situations. Flow under partial penetration is a combination of radial and spherical flow. In steam injection, the situation is complicated by heat injection.

Figures 10 and 11 show the oil/water production histories and water-oil ratio for three cycles for the Aberfeldy formation (Run ABC18, Table 2(a)). In this case, steam is injected into the top 18 ft of the 36 ft formation, at the base of which there is a water zone, 36 ft thick. The results of this run are comparable to those of Run ABC17. A comparison of all Aberfeldy bottom water cyclic simulation runs ABC6, 8, 9, 11, and 17 shows that the oil-steam ratio in all cases is higher than that in the case of the partial penetration run. The important difference is that in the full oil zone interval completion runs, the water-oil ratios are much higher, e.g. 3 in partial completion vs. 200-300 in full completion. It can be said that full interval completion may be practical only if the pumping capacity is large enough, and large volumes of the produced water can be handled.

Partially penetrating cyclic wells do seem to have one advantage: they prevent communication with the bottom water zone, as seen from low water-oil ratios. The very high water-oil ratios in the case of the full interval completions in the bottom water situation are due to communication of the perforations with the bottom water zone. On the other hand, the oil production rate in the partial penetration case is very low initially, but improves in the

succeeding cycles. The water production rate increases also, but the water-oil ratio declines. Possibly, partial penetration oil production would become competitive with the oil production of full-interval completion after several cycles. As such, partial penetration offers an interesting option in cyclic steaming under bottom water conditions.

Effect of Top Water on Cyclic Steaming Performance

As noted previously, in several fields, a high water saturation zone occurs above the oil zone, in communication with it. It is important to examine the geology of such a setting, and have good rock and fluid data available. As pointed out by Tortike (1), in some instances the water-saturated rock is fine grained, indicating that a different set of capillary pressure and relative permeability curves should be employed. The several simulations conducted in this study merely point out salient effects. Figure 12 shows bar charts, with each pair of bars representing a different combination of water-to-oil zone thickness ratio and the ratio of the vertical to horizontal permeabilities. The absolute permeabilities, relative permeabilities and capillary pressure characteristics were the same for the two layers. It was assumed that only the oil zone was perforated in all cases, except in one instance the water zone was also opened for production only.

The high conductivity water zone overlying the oil zone leads to early channelling of steam into the water zone, aggravated by gravity segregation. At a later stage, the steam entering the oil zone also migrates upwards, driving a substantial amount of oil into the well blocks directly above the injection blocks. The top water layer gets heated to nearly the steam temperature in a relatively short time. Figure 12 shows that the oil-steam ratios in the five cases considered were of the order of 0.1. These cases correspond to combinations of water-to-oil thickness ratios of 0.1 and 1.0, and vertical permeability ratios of 1.0 and 0.2. In one case, the water layer was also produced in the production phase. The water-oil ratio was the highest in this case. Although some of the migrated oil was produced, much water had to be produced as a result. It is interesting to note that the vertical permeability ratio appears to be much less important than the top water thickness ratio. This trend was also noticed in the case of bottom water. The above simulation results show the dominant features of top water.

CONCLUSIONS

Based upon the simulations conducted, the following conclusions are offered:

1. Bottom or top water thickness and vertical permeability are important factors in determining cyclic steaming performance. Decreasing steam slugs in succeeding cycles seem to be desirable under such conditions.
2. Partially penetrating cyclic steam stimulation wells might be considered when thick contiguous water zones are present.
3. Top water appears to be even more undesirable than bottom water, in view of migration of oil into the water zone above.

REFERENCE

1. Simon Tortike: Personal Communication (April 1987).

ACKNOWLEDGMENTS

The authors wish to express their appreciation to Dr. G.S. Reddy, Husky Oil Operations Ltd., for helpful comments and suggestions. This work was carried out under an Energy, Mines and Resources, CANMET, Ottawa, contract. The technical support of Dr. Albert George is gratefully acknowledged.

Table 1
RESERVOIR DATA USED IN THE SIMULATIONS

	Aberfeldy Saskatchewan	Cold Lake Alberta
Formation thickness, ft	36	36 to 150
Water zone thickness, ft	3.6 to 36	3.6 to 36
Formation permeabilities, darcy		
k_x	2.0	2.0
k_y	2.0	2.0
k_z	0.4 to 2.0	2.0
Porosity, %	35	35
Reservoir pressure, psi	200	500
Reservoir temp, °F	74	74
Oil viscosity at reservoir temp, cp	1275	125,000
Water compressibility, psi^{-1}	3×10^{-6}	3×10^{-6}
Water thermal expansion coeff., $^{\circ}\text{F}^{-1}$	4.9×10^{-4}	4.9×10^{-4}
Oil compressibility, psi^{-1}	5×10^{-6}	5×10^{-6}
Oil thermal expansion coeff., $^{\circ}\text{F}^{-1}$	5×10^{-4}	5×10^{-4}
Rock compressibility, psi^{-1}	1×10^{-4}	1×10^{-4}
Formation thermal conductivity, Btu/hr-ft-°F	1.76	1.76
Overburden thermal conductivity, Btu/hr-ft-°F	1.47	1.47
Overburden density, lb/ft^3	165	165
Overburden specific heat, Btu/lb-°F	0.20	0.20
Overburden thermal diffusivity, ft^2/hr	0.04	0.04
Relative permeabilities	Figs. 1 & 2	→
S_{wc} , fraction	0.20	0.20
S_{or} , fraction	0.211	0.211
S_{gc} , fraction	0.1	0.1

Table 2 (a)
ABERFELDY CYCLIC STEAMING RUNS & CONDITIONS

Run	Cycle 1			Cycle 2			Cycle 3			Conditions	Notes
	Injection Time	Soak Time	Production Time	Injection Time	Soak Time	Production Time	Injection Time	Soak Time	Production Time		
ABC1	30	5	90	30	5	90	30	5	90	no bottom water	1,2
ABC2	30	5	90	40	5	90	50	5	90	no bottom water	3
ABC3	30	5	90	20	5	90	10	5	90	no bottom water	4
ABC4	30	20	90	30	20	90	30	20	90	no bottom water	5
ABC6	30	5	90	30	5	90	30	5	90	thin bottom water	1,2
ABC8	30	5	90	20	5	90	10	5	90	thin bottom water	3
ABC9	30	20	90	30	20	90	30	20	90	thin bottom water	4
ABC11	30	5	90	30	5	90	30	5	90	thick bottom water	1,2
ABC17	30	5	90	30	5	90	30	5	90	thick bottom water	3
ABC18	30	5	90	30	5	90	30	5	90	thick bottom water	4,6

Note 1: Injection time 30 days, soak time 5 days

Note 2: Same condition in all cycles

Note 3: Injection time 30 days in Cycle 1, 40 days in Cycle 2 and 50 days in Cycle 3, soak time, 5 days

Note 4: Injection time 30 days in Cycle 1, 20 days in Cycle 2 and 10 days in Cycle 3, soak time, 5 days

Note 5: Injection time 30 days, long soak times (20 days), in all cycles

Note 6: Well completed in the upper one-half of the oil zone

Table 2 (b)

ABERFELDY CYCLIC RUNS RESULTS SUMMARY

Run	$\frac{h_w}{h_{oil}}$	Perfs.	Cycle 1				Cycle 2				Cycle 3				Notes	
			time.day	Prod.	OSR	Cum	Oil	Prod.	OSR	Cum.	Oil	Prod.	OSR	Cum.		Oil
					Bbl/Bbl	WOR	Rec.%	time.day	Bbl/Bbl	WOR	Rec.%	time.day	Bbl/Bbl	WOR	Rec.%	
ABC1	0	1-2	90	0	0.103	10.2	.32	0	-	-	-	0	-	-	-	1,2
ABC2	0	1-2	90	90	.151	8.65	.40	90	.086	76.9	.53	7	.053	21.3	.565	3
ABC3	0	1-2	90	90	.151	8.65	.40	90	.132	26.2	.59	90	.1254	27.62	.67	4
ABC4	0	1-2	90	90	.1408	8.75	.38	20	.0874	25.11	.47	0	-	-	-	5
ABC6	0.1	1-1	90	90	.058	31.17	.15	90	.0593	57.6	.30	10	.044	24.2	.34	1,2
ABC8	0.1	1-1	90	90	.058	31.17	.15	90	.079	14.77	.34	90	.091	17.11	.47	3
ABC9	0.1	1-1	90	90	.055	32.12	.14	17	.0395	20.4	.20	0	-	-	-	4
ABC11	1.0	1-1	90	90	.082	16.8	.158	90	.0477	374.	.184	0	-	-	-	1,2
ABC17	1.0	1-1	90	90	.081	16.53	.155	90	.054	132.8	.206	13	.038	126.7	.221	3
ABC18	1.0	1-1	90	90	.0056	3.85	.011	90	.0114	4.60	.044	90	.022	2.97	.129	3,6

Note 1: Injection time 30 days, soak time 5 days

Note 2: Same condition in all cycles

Table 2(b) continued

Note 3:	Injection time 30 days in Cycle 1, 40 days in Cycle 2 and 50 days in Cycle 3, soak time, 5 days
Note 4:	Injection time 30 days in Cycle 1, 20 days in Cycle 2 and 10 days in Cycle 3, soak time, 5 days
Note 5:	Injection time 30 days, long soak times (20 days), in all cycles
Note 6:	Well completed in the upper one-half of the oil zone

ABERFELDY FIELD, SASKATCHEWAN

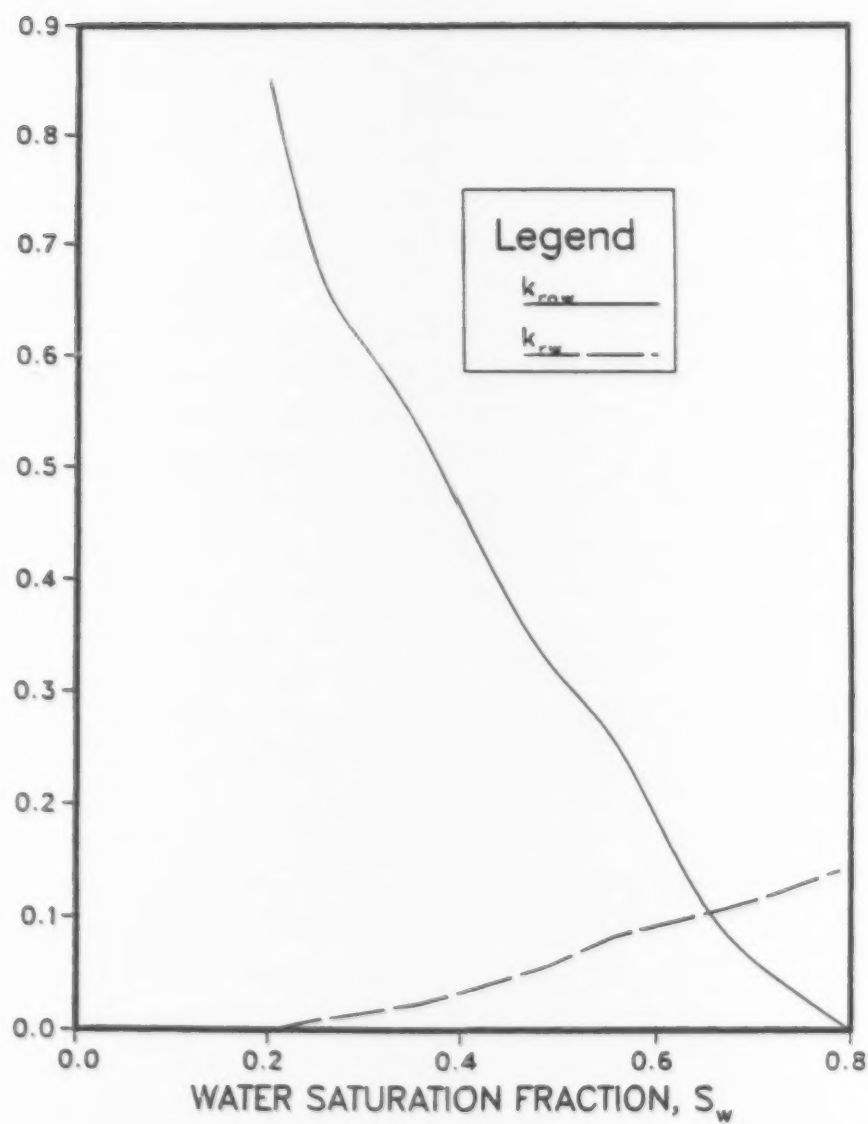


Figure 1 - Aberfeldy Formation Water-Oil Relative Permeability Curves.

ABERFELDY FIELD, SASKATCHEWAN

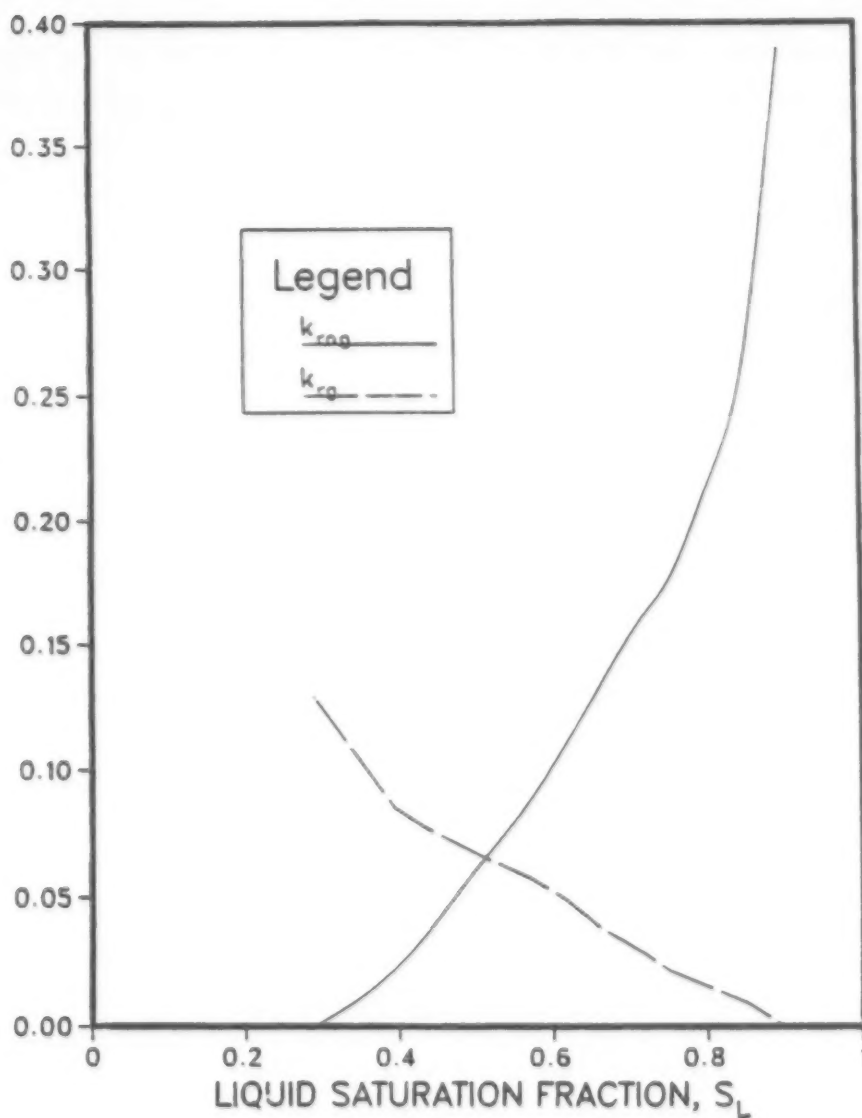


Figure 2 - Aberfeldy Formation Gas-Oil Relative Permeability Curves.

ABERFELDY FIELD, SASKATCHEWAN

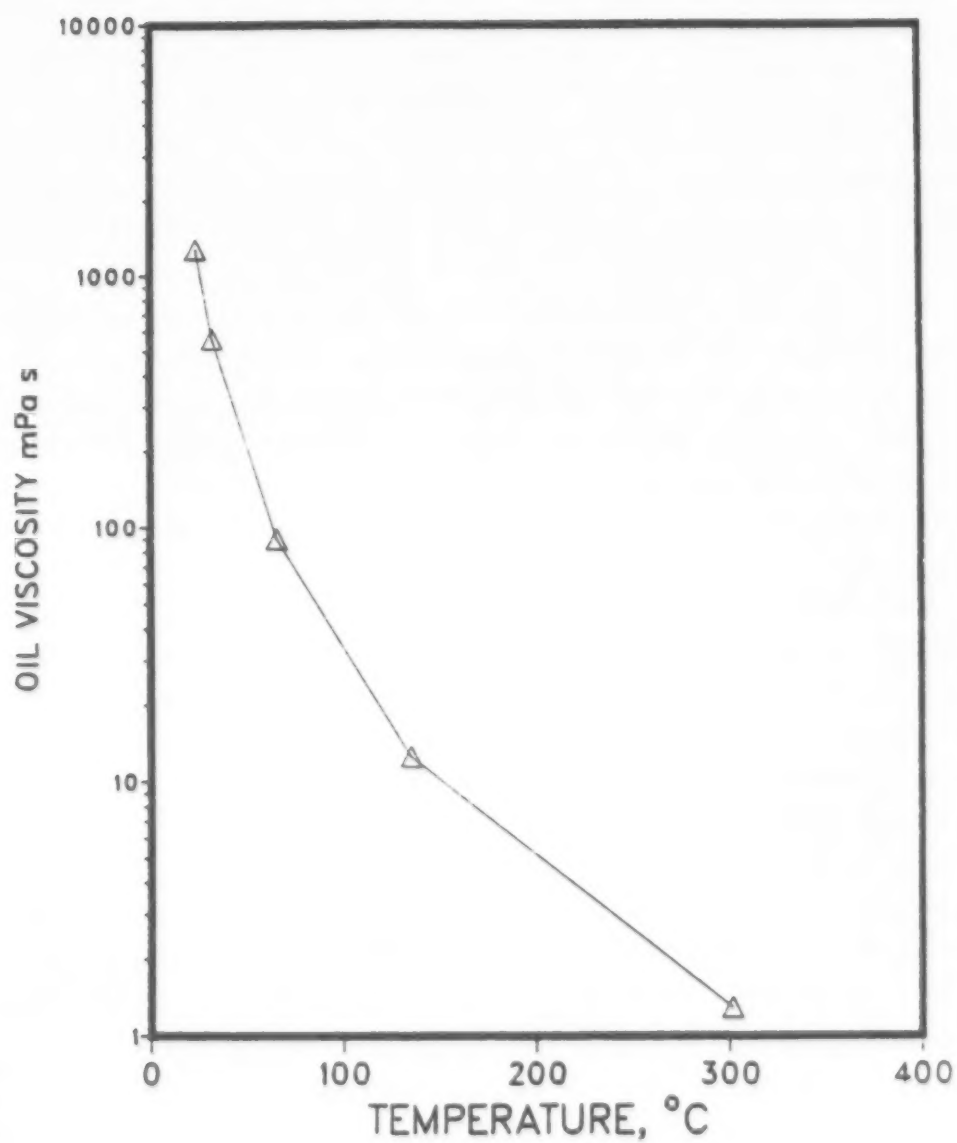


Figure 3 - Aberfeldy Oil Viscosity-Temperature Relationship (log plot)

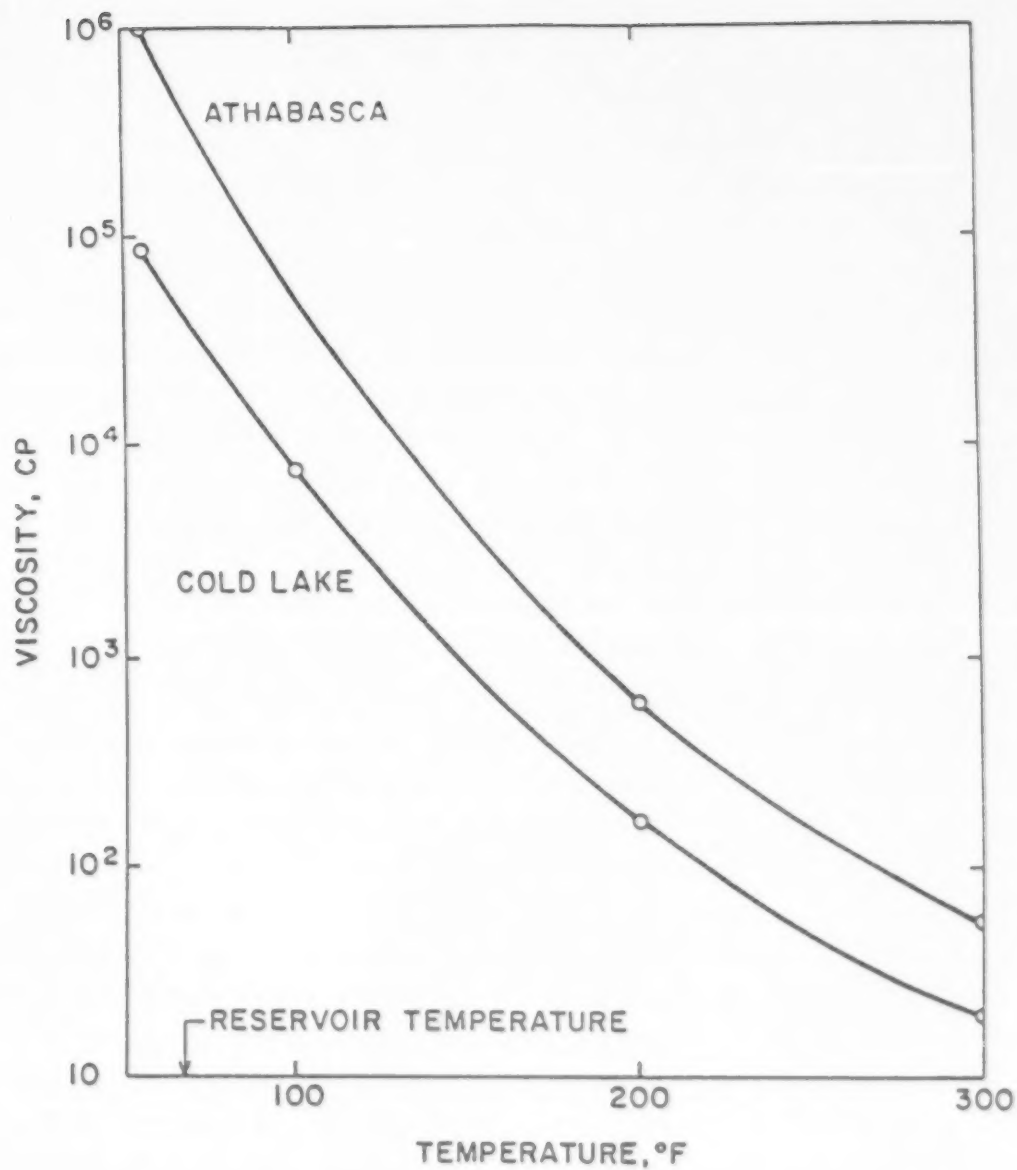


Figure 4 - Viscosity of the Cold Lake Crude Oil.

**CYCLIC STEAMING RUN ABC 3, ABERFELDY
NO BOTTOM WATER**

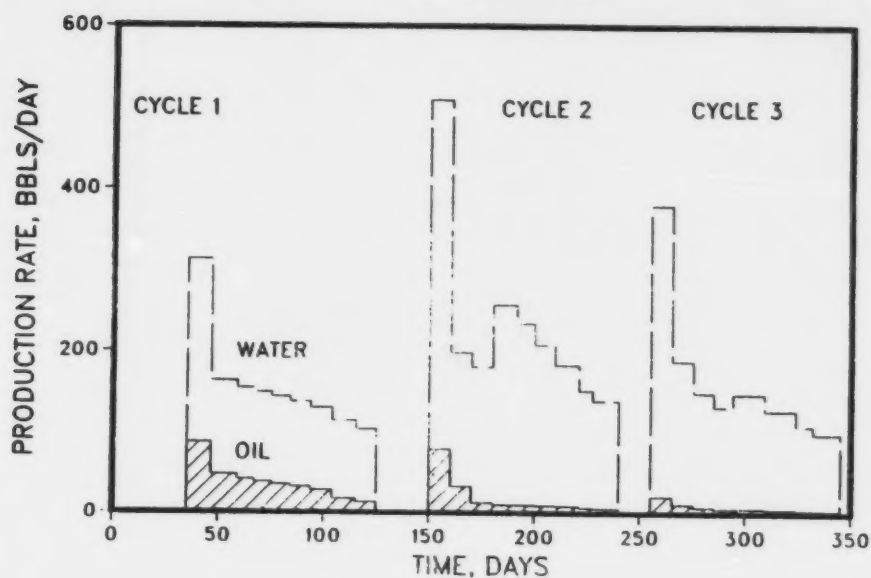


Figure 5 - Production History for Aberfeldy Cyclic Run ABC3, No Bottom Water

**CYCLIC STEAMING RUN ABC 3, ABERFELDY
NO BOTTOM WATER**

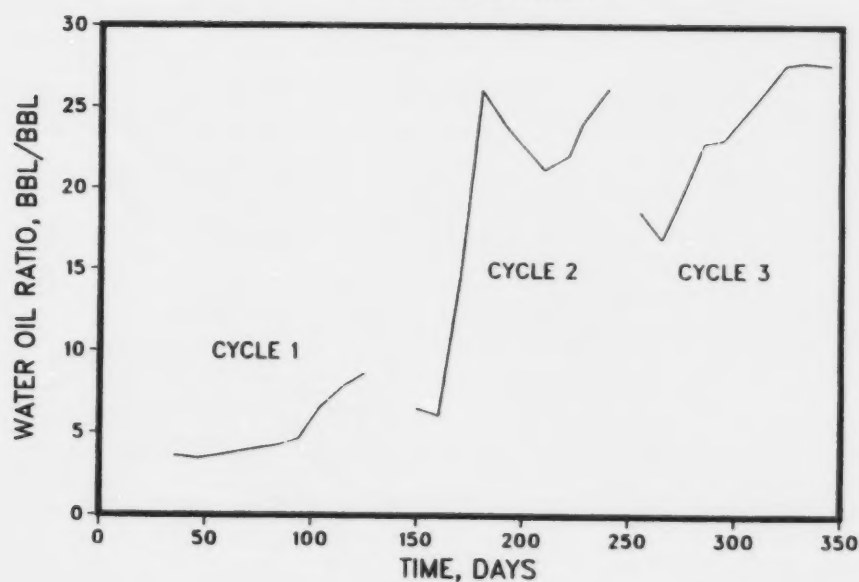


Figure 6 - Water-Oil Ratio for Aberfeldy Cyclic Run ABC3, No Bottom Water

CYCLIC STEAMING RUN ABC 8, ABERFELDY BOTTOM WATER

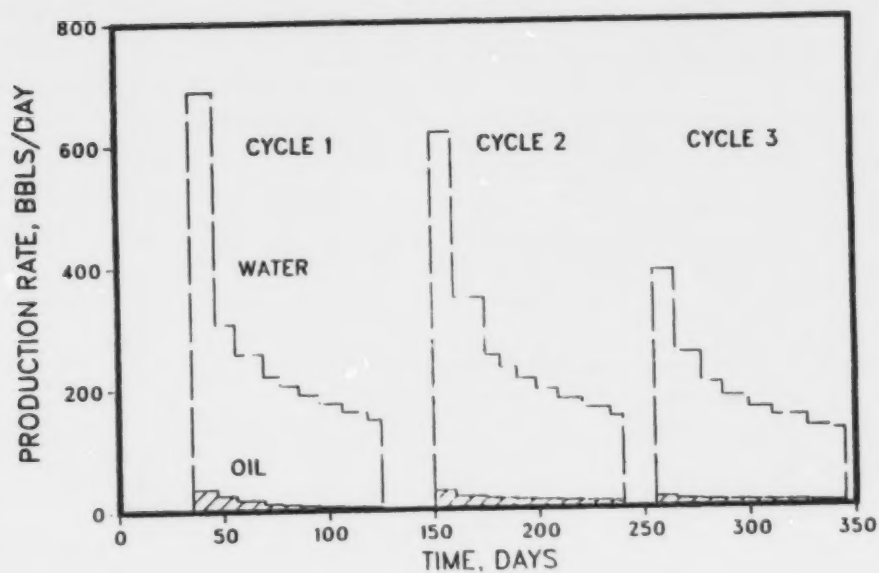


Figure 7 - Production History for Aberfeldy Cyclic Run ABC 8, Bottom Water

CYCLIC STEAMING RUN ABC 8, ABERFELDY BOTTOM WATER

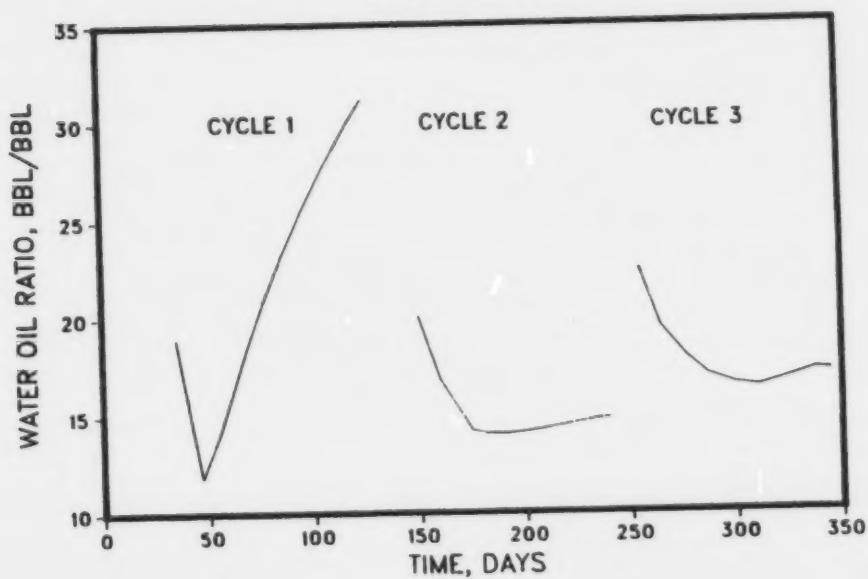


Figure 8 - Water-Oil Ratio for Aberfeldy Cyclic Run ABC 8, Bottom Water

**CYCLIC STEAMING RUN ABC 11, ABERFELDY
BOTTOM WATER**

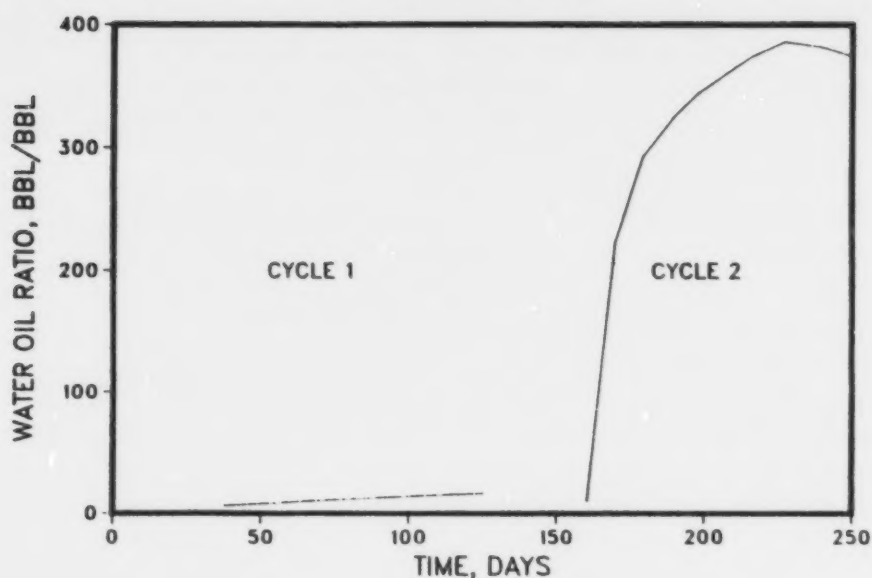


Figure 9 - Water-Oil Ratio for Aberfeldy Cyclic Run ABC11, Bottom Water

**BOTTOM WATER, 36FT/36FT, CYCLIC RUN: ABERFELDY RUN ABC18
PARTIAL PENETRATION; COMPLETION TOP 18 FT
STEAM INJ. 30 DAYS; SOAK 5 DAYS**

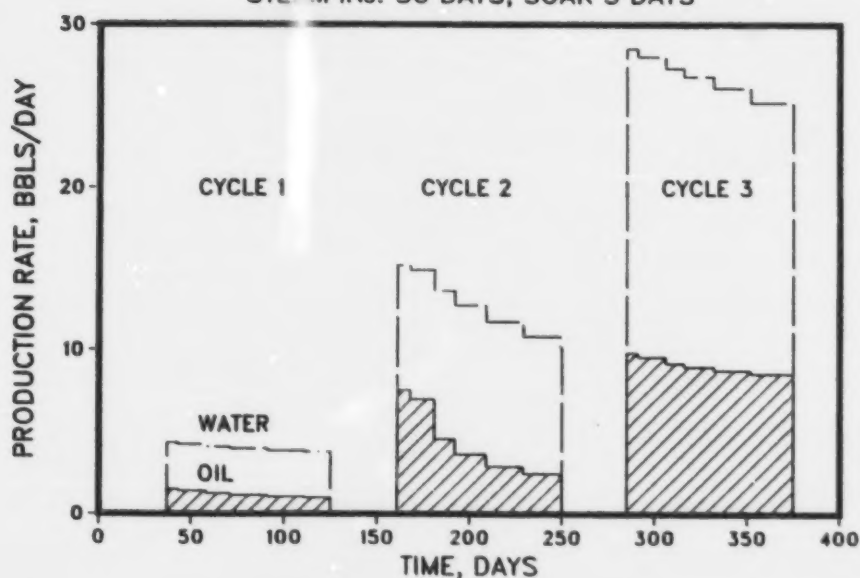


Figure 10 - Production History of Aberfeldy Cyclic Run ABC18, for Partial Penetration

BOTTOM WATER, 36FT/36FT, CYCLIC RUN: ABERFELDY RUN ABC18
PARTIAL PENETRATION; COMPLETION TOP 18 FT
STEAM INJ. 30 DAYS; SOAK 5 DAYS

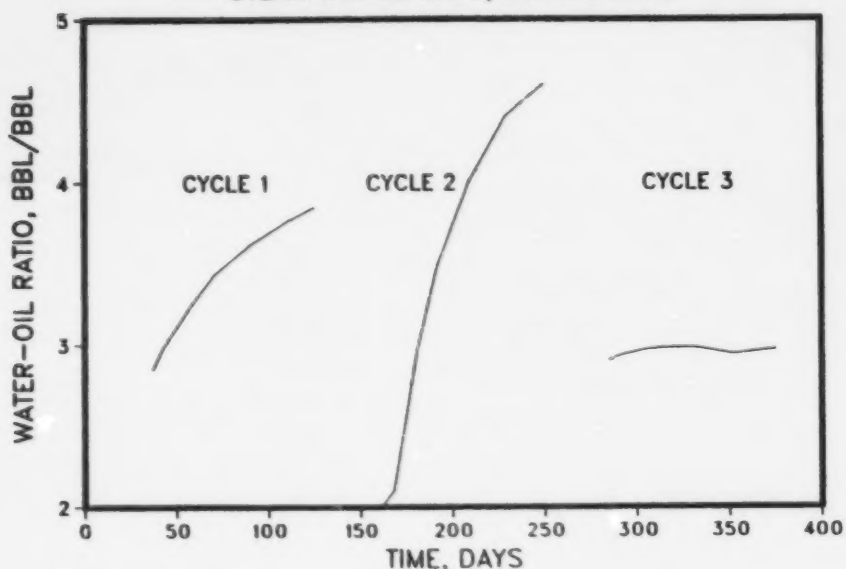


Figure 11 - Water-Oil Ratio of Aberfeldy Cyclic Run ABC18, for Partial Penetration

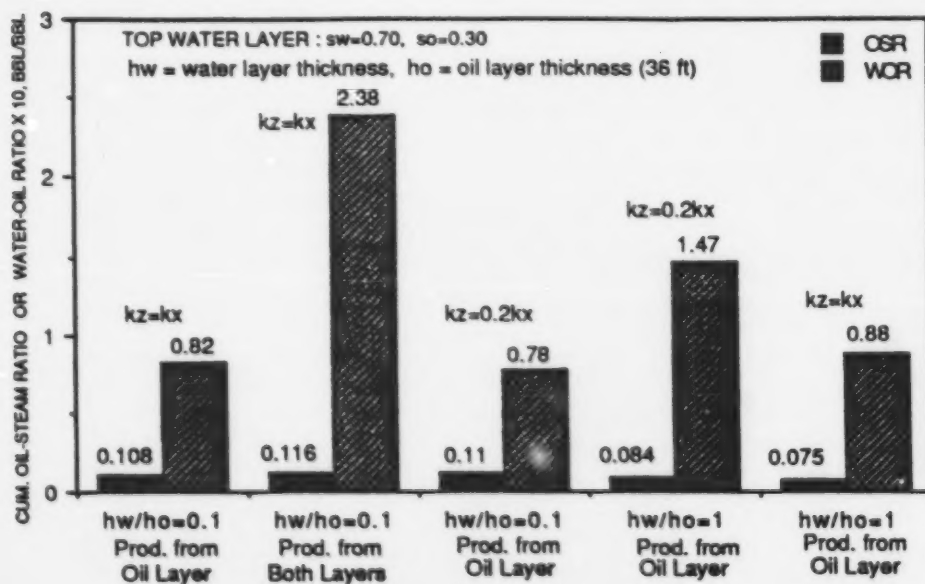


Fig. 12-First Cycle, Cumulative Steam-Oil and Water-Oil Ratios, for Various Operating Conditions. Injection into the (Bottom) Oil Layer Only.

SPE 18784

Role of Foam, Non-Newtonian Flow, and Thermal Upgrading in Steam Injection

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This paper was prepared for presentation at the SPE California Regional Meeting held in Bakersfield, California, April 5-7, 1989.

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ABSTRACT

Foam formation and flow, non-Newtonian behaviour, and thermal upgrading phenomena play a role in steam injection processes, which is still not clearly understood. This investigation addresses these effects in the context of steamflooding. The results are based upon a steam injection simulator, which was modified to account for foam, non-Newtonian oil viscosity, and thermal upgrading.

Steam-foam flow was represented by means of a shear-dependent mobility, which was also a function of pressure, temperature, foam quality, and flow velocity. The relative permeability to gas was also a function of surfactant concentration. Non-Newtonian flow behaviour was implemented in the conventional manner, making the apparent viscosity of oil a function of local shear rate. Thermal upgrading was represented as a permanent decrease in oil viscosity depending on the residence time and temperature. These effects were incorporated into a three-phase, three-dimensional, fully implicit steam simulator.

It was found that a steam foam led to an increase in oil production rate, compared to steam alone. However, the increase was small, since the foam acted to increase steam viscosity, although the blocking effect was present to a small extent. The oil production behaviour in the case of a non-Newtonian oil was superior to that for a Newtonian oil, because the apparent viscosity of oil decreased in the cold part of the reservoir. Thermal upgrading, on the other

hand, was less effective in increasing oil recovery, because the oil viscosity decrease due to cracking, over and above that due to temperature, was small.

INTRODUCTION

At the present time, steam injection is the most successful EOR method, as evidenced by the commercial cyclic steam stimulation operations in Alberta, and steamfloods (combined with cyclic steaming) in California. Over the years, numerical simulators of steam injection processes have improved in describing the processes in question in a more comprehensive manner. This study is directed toward the numerical simulation and effects of three phenomena that may be important in steam injection, viz. foam flow, non-Newtonian oil viscosity and thermal upgrading. Laboratory data reported in the literature was used to construct suitable models of the aforesaid phenomena, which were built into a fully implicit simulator. These models will be described in detail, followed by a discussion of several representative simulator runs.

FLOW OF FOAMS IN POROUS MEDIA

Rheology of Foam

Foams are complex two-phase, multicomponent fluid systems, with rather unusual flow behaviour in a porous medium. A foam is basically a gas-liquid dispersion that is formed by mixing a gas, such as air or nitrogen, and a liquid to which a surface active agent has been added. A number of previous studies have been devoted to foam rheology in a variety of flow systems, such

as laboratory containers, capillary tubes, and porous media (e.g. Bernard (1963), Holm (1968), Raza (1970), and Mast (1972)). Irani and Solomon (1986) discussed the mechanics of CO₂-foam propagation in a slim tube, and foam stability. A brief description of some of the dominant characteristics of foam are given below. A few studies have also dealt with "oil foams", i.e. dispersions of oil, containing a surface active agent and a gas. Such foams are usually unstable, and will not be considered here.

Fried (1961) conducted the first comprehensive study on the flow of foams in a porous medium. Although this work was done over 25 years ago, it is still useful for reasons of its thoroughness. It was reported that the mobility of an externally generated foam in a porous medium was considerably lower than that of the gas used for the foam. Foam can be generated by injecting gas into a porous medium that initially contains a foaming solution. This was assumed in the present study. Raza and Marsden (1967) and Raza (1970), showed that anionic foaming agents produce low quality, stable foams, while nonionic agents yield high quality, unstable foams. (Foam quality is defined as the ratio of gas volume to the total foam volume.) Flow tests in a porous medium showed that the foam quality increased as the surfactant concentration increased until a concentration of 0.1% by weight was reached, after which the quality became constant. The time for foam breakthrough was very small up to a surfactant concentration of 0.1%. Thereafter, the breakthrough time increased 20-fold, reaching a maximum.

Based upon Minssieux's work (1974), possibly in the flow of an aqueous foam, liquid drainage is the dominant mechanism deciding foam stability. Regarding the effect of temperature and pressure on foam stability, it appears that generally foam stability increases with increasing pressure, and decreases with increasing temperature. The quality decreases with an increase in pressure and/or decrease in temperature, for a given surfactant condition. These results are based upon Wang's (1984) and Maini and Ma's (1984) work. These effects were built into the equations developed for the present study.

The mobility reduction factor of foams increases with increasing foam stability. The apparent viscosity of foam depends on a number of factors, including velocity or shear rate, pressure, and temperature. An increase in pressure causes a decrease in the foam quality, and an increase in density. The apparent viscosity of foam is often expressed as a function of foam density, with the viscosity passing through a maximum as

the density increases (Grove et al (1951)). It has been shown by Marsden and Khan (1966) that the apparent viscosity decreases with increasing shear rate and increases with increasing quality. Shear stress versus shear rate plots for foams tend to show that foams have pseudoplastic behaviour. Flow experiments in capillary tubes have shown that the apparent viscosity also depends on the tube radius (Raza and Marsden (1967)). Correcting for slippage and compressibility, it was found that the foam viscosity became independent of quality, but continued to be a function of tube diameter. The apparent viscosity of a foam was found to decrease with temperature.

Hirasaki and Lawson (1983) proposed a mathematical equation for the apparent viscosity of foam. The viscosity was attributed to: (i) the liquid slugs, (ii) resistance to deformation of the interface of a bubble passing through a capillary and (iii) surface tension gradient. Recently, Falls et al (1988) presented a new model of foam flow, comprising foam generation by capillary snap-off.

Flow in Porous Media

The early work of Fried (1961), and later Bernard (1964) showed that the mobility of foam in a porous medium is lower than that of gas or the liquid constituting the foam. The latter study also showed that the displacement efficiency of a foam was higher in sand packs containing water only as compared to sand packs containing oil only. When both oil and water were present, the performance was somewhere in between. Further studies have shown (Bernard (1964)) that the relative permeability to water as a function of water saturation is not altered in the presence of foam, however, that of the gas is lowered, because the effect of foam is to create a higher trapped gas saturation, which indirectly lowers the relative permeability to water. The presence of oil tends to lower the trapped gas saturation.

There is some difference of opinion on the mechanics of flow of a foam in a porous medium. Marsden and Khan (1966) suggested that the foam components flow simultaneously in a porous medium. Thus, foam mobility was found to decrease with increasing quality. On the other hand, Bernard et al. (1964) proposed that water flows as a continuous phase, while the gas is a discontinuous phase. Still another mechanistic picture was described by Holm (1968), who observed in visual studies that the gas and liquid phases flowed separately in a porous medium by the breaking and reforming of the bubbles. Foam generation and quality have been related to absolute permeability (Raza (1970)). Foam is generated in the longer pores, wherein the foam would tend to flow, with temporary

blockage in the smaller pores. In this manner, it is possible to describe the flow of a foam in a porous medium in at least two different ways: as a single body, or as two separate phases. In any case, the flow behaviour is non-Newtonian.

Application of Foam in Steam Injection

A foam is used in steam injection for two purposes, which are not distinct. First, injected with steam it can help control steam mobility, because steam will act as a viscous fluid leading to higher displacement efficiency of the mobilized oil. Second, foam can also act as a blocking agent, where gravity override of steam has created a high conductivity path in the upper part of the formation. Steam mobility control by use of foam is likely to be more effective in steamflooding lighter oils, where the steam front is close to vertical. When steam override is present, use of foam as a blocking agent is likely to be more effective. In both cases, formation and flow of foam leads to a large reduction in gas phase mobility.

Elson and Marsden (1978) have reviewed the literature on the use of foam with steam, concluding that foam is best suited as a blocking agent. Chiang et al. (1980) carried out ambient temperature experiments using a surfactant and water, with nitrogen as gas. They reported that *in situ* formation of foam increased liquid recovery and reduced gravity override. Isaacs et al. (1985) reported steam-foam experiments, showing that steam-foams were formed in the case of one of the surfactants, as indicated by the large pressure drop, when steam was injected. On the other hand, no foam was formed in the case of the other surfactant. They reported that the gas phase relative permeability curves had to be shifted depending on gas velocity and surfactant concentration in order to simulate foam flow. In a recent study, Isaacs et al. (1988) described experimental results on the formation of a steam foam starting with a gas. Steam velocity and permeability were among the more important factors determining foam stability.

Representation of Foam in the Mathematical Model

In the present mathematical model, foam was considered to have two effects on steam flow: it increases the apparent viscosity of the steam phase, and it reduces the relative permeability to gas. In the existing literature, there are no consistent data describing foam rheology as a function of surfactant concentration, quality, temperature, and pressure. The same is true for the relative permeability to gas in the presence of a foam. The purpose of this work was to put together the available data in a

form in which the dominant aspects of foam flow are represented. The input consisted of the surfactant concentration in the steam zone. This was used to calculate the foam quality. The quality was modified for pressure and temperature effects. Finally, the computed quality was used in the viscosity equation, to calculate the apparent viscosity of foam. In a similar way, the relative permeability to gas was based upon the flow velocity, assuming the presence of a foam after Isaacs et al. (1985). The equations used are as follows, and are based upon the experimental data of Wang (1984), Grove (1951), Marsden and Khan (1966), and Best et al. (1985).

$$x = 1.14205 (0.7975 - 0.90763 C_s) \\ (0.36 + 3.2 \times 10^{-4} p) \exp (-0.001594 T), \quad (1)$$

$$(75 \leq T \leq 140^\circ\text{F}, 1500 \leq p \leq 2000 \text{ psia}, \\ 0.1 \leq C_s \leq 0.33\% \text{ by wt})$$

where x is foam quality, fraction, C_s is concentration in steam, fraction, p is pressure in psia, and T is temperature in $^\circ\text{F}$. The apparent viscosity of foam is given by

$$\mu_{\text{app}} = -386 + 783 x - 0.4211 \dot{\gamma}, \\ (0.7 \leq x \leq 0.95, 100 \leq \dot{\gamma} \leq 300 \text{ min}^{-1})$$

where $\dot{\gamma}$ is the shear rate, related to velocity v by (Jennings et al. (1971))

$$\dot{\gamma} = \frac{299 v}{\sqrt{kf}}, \quad (3)$$

where v is in ft/day, k is permeability in darcies, and f is porosity, fraction. Notice that the above equations are valid only over a limited range of the variables involved. The relative permeability to gas is similarly given by

$$k_{rg} = k_{rg0} (0.1 + 0.3092 v), \quad (4)$$

where k_{rg0} is relative permeability to gas in the absence of foam. This is a rough approximation, and only reflects the observed trend.

Non-Newtonian Oil Viscosity

Non-Newtonian oil viscosity is considered to be a function of temperature, pressure, gas solubility, and shear rate. The oil viscosity as a function of temperature is given by Andrade's equation, or Beggs and Robinson's (1975) correlation, if gas in solution is to be taken into consideration. Non-Newtonian oil viscosity was expressed by the following equation, which serves for illustrative purposes only:

$$\mu_o = \mu_{o0} \dot{\gamma}^{-1} \quad (5)$$

where μ_{o0} is the apparent non-Newtonian viscosity. It is possible to determine whether a fluid exhibits non-Newtonian

behaviour by giving a value of shear rate to Equation (5) that determines the oil viscosity. With flow in porous media, a range of shear rates occurs at any average

throughput. An average shear rate $\bar{\gamma}$ can be used to represent the shear rates that exist within each grid block in the reservoir corresponding to the block velocity. By

using $\bar{\gamma}$ and Equation (5), a non-Newtonian viscosity for the flowing fluid can be obtained, for the average velocity $\bar{v}$. The average velocity in a three-dimensional block is given by

$$\bar{v} = \frac{q}{A\Delta} \quad (6)$$

where $\bar{q}$ is the average flow rate in the block, i.e.,

$$\left(\frac{q}{A}\right) = \left\{ \left[\left(\frac{q}{A}\right)_{i+1,j,k} + \left(\frac{q}{A}\right)_{i-1,j,k} \right]^2 + \left[\left(\frac{q}{A}\right)_{i,j+1,k} + \left(\frac{q}{A}\right)_{i,j-1,k} \right]^2 + \left[\left(\frac{q}{A}\right)_{i,j,k+1} + \left(\frac{q}{A}\right)_{i,j,k-1} \right]^2 \right\}^{1/2} \quad (7)$$

The characteristic length in the porous medium is defined by McKinley et al. (1966) to be:

$$l = C\sqrt{k/\bar{\epsilon}} \quad (8)$$

The constant C is related to the pore size distribution and tortuosity of the porous medium, and can be expressed as a function of permeability as follows (Gogarty, 1967):

$$l = f(k)\sqrt{k/\bar{\epsilon}} \quad (9)$$

The average shear rate, obtained in this manner, can be obtained by dividing Equation (4.116) by Equation (4.119) as follows:

$$\bar{\gamma} = \frac{3.55\bar{v}}{f(k)\sqrt{k/\phi}}$$

where the functional form of $f(k)$ can be written as:

$$f(k) = m \log \frac{k}{k_1} + \bar{\gamma}$$

In the above equation, the constants m and P depend on the fluid properties for a given rock. In this study, $f(k)$ was taken to be unity (Gogarty (1967)). Equation (10) can be used to calculate the local shear rate in the porous medium, which is then substituted into Equation (11) to obtain the apparent viscosity at that point and time.

THERMAL UPGRADING OF HEAVY OILS

A heavy crude oil, when subjected to mild thermal cracking conditions, exhibits a permanent and considerable reduction in its viscosity and specific gravity. All crudes are susceptible to cracking, however, high temperatures and long times are required to crack heavy crudes, such as the Athabasca

bitumen. By subjecting both the original crude and the heat-treated oil to distillation under identical conditions, the amount of upgrading or conversion of crude constituents can be estimated.

Laboratory tests have been conducted on a variety of crude oils, in order to study the time-temperature history, and to obtain specific degrees of viscosity reduction for each sample. Therefore, it is possible to determine the feasibility of applying heat in the reservoir to facilitate the production of heavy oil, or of utilizing heat to make the surface handling of the oil already produced easier.

At 500° F, the permanent upgrading of physical properties takes place rather slowly. Use of temperatures lower than that will only improve the oil fluidity, which is the case of heated pipelines as currently practiced. On the other hand, at temperatures above 700° F, coking may take place, which will cause operating problems.

Crude oils having low API gravities and high viscosities and pour points cause production difficulties both in and out of the reservoir. In order to avoid surface handling problems, light oils and LPG are blended with heavy crudes to facilitate their handling in pipelines and storage facilities. An alternative technique is to apply thermal cracking. Underground thermal processes may subject large volumes of reservoir crude to a temperature, which is high enough to cause mild thermal cracking. The permanent change in the physical properties of heavy oil as a result of mild thermal cracking was observed by Ball (1941) on oil from the Athabasca oil sands.

Mild thermal cracking or visbreaking is a suggested process in oil recovery to make the oils more pumpable. Mild decomposition, minimum coke formation and the retention of the cracked part in the original crude are characteristics of visbreaking. The oil which has been subjected to the visbreaking process will have lower viscosity, pour point, and specific gravity than the original sample. Therefore, the visbroken crude is upgraded in its physical properties as far as the fluidity is concerned.

In a survey by Henderson and Weber (1965), mild thermal cracking experiments carried out on samples of seven different crude oils have been reported. Six of these samples were chosen from conventional oil reservoirs and one was from the Athabasca oil sands. In this study, Henderson and Weber were concerned about (i) the time that a particular crude could be heated at different temperatures; (ii) establishing a relationship between changes in the crude and

the period of heating; and (iii) the important variables of the process. These variables are discussed in the next section.

Kinetics of the Cracking Process

In a thermal cracking process large molecules of hydrocarbons are ruptured by thermal energy into smaller molecules. Under normal conditions, some small molecules form, which are relatively stable gases or liquids. Also, some unstable or reactive molecules are produced that can polymerize with one another and yield larger molecules than those in the original crude. Provided the pyrolysis is continued for sufficient time, or the temperature is further increased, the original crude will be almost entirely converted into a mixture of light gases (e.g. methane and hydrogen), which are stable, and a solid material, which is coke. Henderson and Weber (1965) gave the following kinetic equation to describe the cracking reaction of pure hydrocarbons as well as petroleum:

$$\ln \left(\frac{C_0}{C} \right) = kt \quad (12)$$

This is the integrated form of the first order rate equation, where C_0 is percent weight of reactant initially present, C is the percent of reactant remaining at time t , in seconds, and k is specific rate or velocity constant, $1/\text{sec}$. The specific rate k is given by the integrated Arrhenius equation

$$k = Ae^{-\frac{E}{RT}} \quad (13)$$

where A is pre-exponent, $1/\text{sec}$, E is activation energy, Btu/lb-mole , T is absolute temperature, $^{\circ}\text{R}$, R is gas constant = $1.987 \text{ Btu/lb-mole-}^{\circ}\text{R}$.

Shu and Venkatesan (1984) described a simple and effective visbreaking model, which was employed in a steamflood simulation study by Shu and Hartman (1986). Results showed that the location of visbroken oil with respect to the direction of steam flow determined the importance of visbreaking.

Representation of Upgrading in the Model

For the purpose of this study, the upgrading process was represented via an oil viscosity equation, where the viscosity is a function of the fraction upgraded, as follows:

$$\ln \mu = a + b(1 - e^{-\frac{t}{\tau}}) \quad (14)$$

where μ is the viscosity at 150°F in cp , T is in $^{\circ}\text{R}$, and t is in seconds. The constants a and b were taken from Henderson and Weber's experimental data, for three of the oils tested by them. These are listed in Table 1.

DISCUSSION OF RESULTS

Simulation Details

The simulations were carried out for a 1275 cp (74°F) Saskatchewan oil, using a fully implicit three-dimensional steam simulator. The five-spot pattern size was 20 acres, and the formation thickness was 36 ft, represented by two layers. Permeability was 2 darcies, and the initial pressure was 200 psi. In the runs reported here, the steam injection rate was 600 B/D.

Non-Newtonian Oil Viscosity Effects

A possible model was discussed for non-Newtonian oils in the previous section. It has been claimed that certain Alberta, Saskatchewan and Venezuela oils behave in the non-Newtonian manner. In the present work, it is intended to show the effect of such oil rheology on steamflooding response. Figure 1 gives the oil/water production history while Fig. 2 gives the oil-steam ratio for the base run SP1, in which none of the aforementioned effects was present. The oil recovery at the end of 843 days is seen to be 12.47%, with a cumulative oil-steam ratio of 0.413.

Figure 3 gives the production history of the same run, but with the assumption that the oil is non-Newtonian, with an exponent of 0.9, at all temperatures (Run SP5). The effect of such a value of the exponent will be to reduce the oil viscosity by one-half approximately, at typical shear rates involved. Figure 2 shows the oil-steam ratio for this run. It is seen that the oil recovery at the same steam injection time is 8.24% versus 4.15% for Newtonian behaviour (626 days). The corresponding oil-steam ratios are 0.367 and 0.185, respectively. The increase in oil recovery and the oil-steam ratio is due to decreased oil viscosity in the non-Newtonian case. It is important to note that within our assumptions, such a decrease is occurring regardless of temperature. In other words, the cold oil mobility is increased, and the oil behaves like a less viscous oil, although in a nonlinear manner. The observed improvements in performance would be obtained also if the steamflood is carried out in a less viscous oil.

In a typical steamflood, oil-water emulsions may form in certain temperature regions, although these were not considered in this work. Such emulsions would behave in a non-Newtonian manner. Depending on the rheology of such emulsions, they may not reduce oil mobility, if they are shear-thinning.

Thermal Upgrading

Thermal upgrading was discussed in the previous section, where a mathematical

representation was given of the thermal upgrading process. Using the viscosity model developed, Run SP3 was carried out. The results were virtually the same as those for the base run (Figs. 1 and 2), with 0.1% higher oil recovery. An examination of the temperature profiles showed that the reason for the small upgrading effect on oil recovery was the fact that the upgrading process lowered oil viscosity only in the parts of the reservoir with high temperatures, where the oil was mobile enough already. Upgrading had no effect on oil viscosity in the cold parts of the formation where it could have done some good. A second run (SP4) was carried out with slightly higher upgrading parameters. The simulation results are plotted in Figs. 4 and 2 for this run. There is a small improvement in this case, with oil recovery increasing to 13.02%.

It can be said that thermal upgrading is not likely to be significant in steamfloods of short duration, and prior to steam breakthrough. If a steamflood is continued after steam breakthrough, the oil around the producers would undergo some thermal upgrading leading to a reduction in viscosity. Also, in long-term projects, utilizing conductive heating of oil, thermal upgrading would be an important factor (e.g. Peace River project). It is thus desirable to include thermal upgrading effects in a steam injection simulator.

Foam Injection

Injection of a thermally stable foam prior to steam, or with steam, is being tested in the field. Foams are known to reduce the relative permeability to gas, without affecting oil relative permeability to any appreciable degree. In steam injection, foams are primarily being applied as diverting or blocking agents, with limited success. In the present work, a foam is considered to be a gas (steam) permeability reducing agent, plus a viscous material, the viscosity of which is shear-dependent. The foam model was discussed in the previous section. The results for a run, comparable to the base run, but with the difference that a foam was assumed to be injected are given in Figs. 5 and 2. It is seen that foam injection leads to an increase in oil recovery as well as oil-steam ratio, these being 13.69% and 0.453, respectively, as compared to 12.47% and 0.413 for the base run. The increase is not large, considering the additional expense of foam injection. Temperature and saturation profiles showed that the foam did divert the steam into the lower part of the formation, where a considerable steam saturation developed. The representation of foam in this model is not rigorous. Very little useable and consistent data is available for high temperature foams.

Quite apart from that, the inclusion of a foam breakdown temperature in the simulator limits the range of effectiveness of a foam injected with steam.

CONCLUSIONS

This investigation presented simulations of steam injection processes, with a number of new features. The model examined the phenomena of thermal upgrading, non-Newtonian oil rheology and steam-foam injection in the context of steamflooding. Thermal upgrading, non-Newtonian oil rheology, and foam flow can be important processes in steam injection, and should be included in any simulation. This observation is based upon numerous simulations, although approximate representations of these processes. Thermal upgrading is effective in only the high temperature regions of a steamflood, over long periods. Non-Newtonian oil behaviour (in this case, shear-thinning) will affect oil viscosity over the entire reservoir, leading to an increase in oil recovery over the case where the oil viscosity is shear-invariant. Foam injection with steam was only a little more effective than steam alone, within the framework of the foam model used in this work.

ACKNOWLEDGMENT

The financial support of CANMET, Energy, Mines and Resources, Government of Canada, is gratefully acknowledged.

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Table 1

KINETICS CONSTANTS USED FOR UPGRADING

Crude Oil	Log ₁₀ A	Activation Energy, E, kcal/mole	b	a
C	12.13	49.0	-10.067	6.7832
E*	9.86	43.6	-6.299	4.2896
Athabasca Bitumen	11.53	49.	-11.16	7.253

* Crude oil simulated

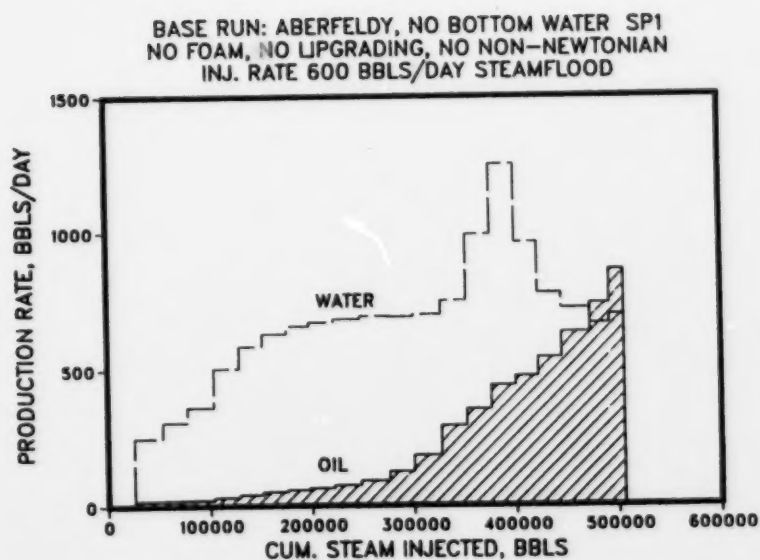


Figure 1 - Production History of Base Aberfeldy Steamflood Run SP1, for Special Features Studies

UPGRADING RUN: ABERFELDY, NO BOTTOM WATER SP4
 INJ. RATE 600 BBLS/DAY STEAMFLOOD

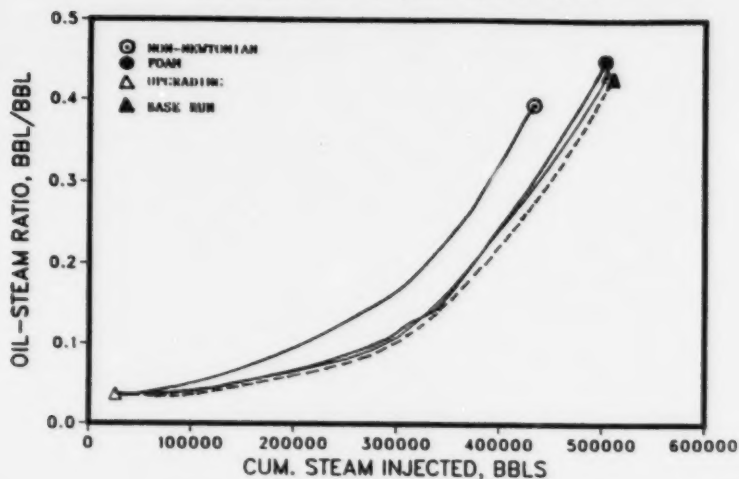


Figure 2 - Oil-Steam Ratio of Aberfeldy Run SP4, for Oil Thermal Upgrading

NON-NEWTONIAN RUN: ABERFELDY, NO BOTTOM WATER SP5
 INJ. RATE 600 BBLS/DAY STEAMFLOOD

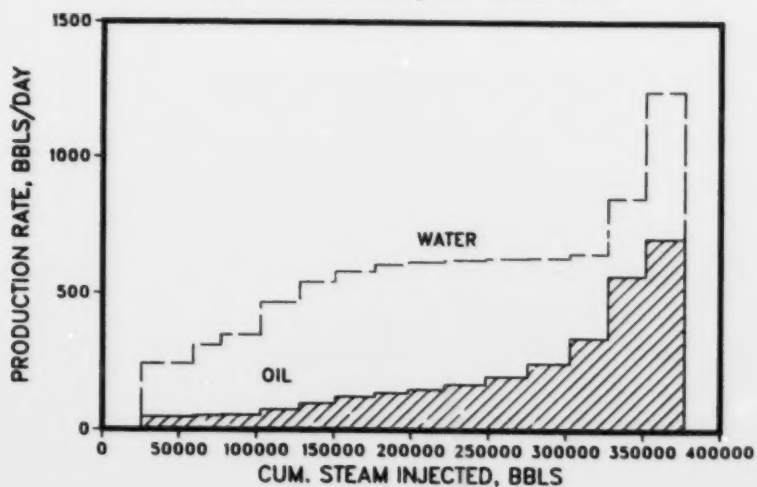


Figure 3 - Production History of Aberfeldy Run SP5, for Non-Newtonian Oil ($n = 0.9$)

UPGRADING RUN: ABERFELDY, NO BOTTOM WATER SP4
INJ. RATE 600 BBLS/DAY STEAMFLOOD

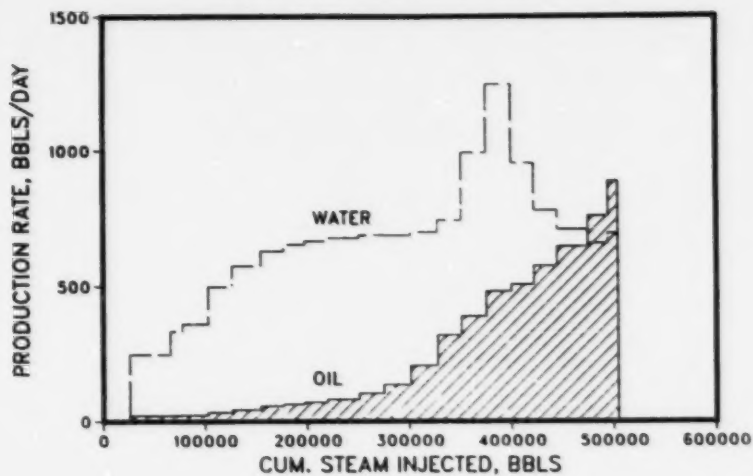


Figure 4 - Production History of Aberfeldy Run SP4, for Oil Thermal Upgrading

FOAM RUN: ABERFELDY, NO BOTTOM WATER SP2
INJ. RATE 600 BBLS/DAY STEAMFLOOD

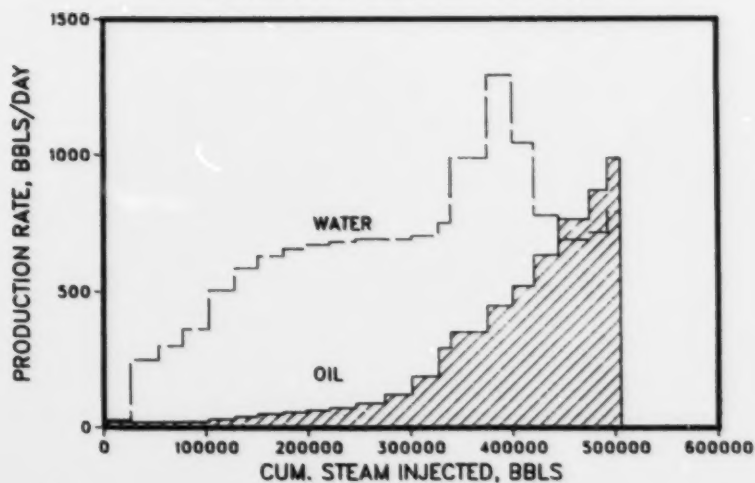


Figure 5 - Production History of Aberfeldy Run SP2, for Steam Foam Injection

SPE 17451

Effect of Wellbore Steam Quality Variation on Steamflooding Thick Formations

by M. Kasraie, BP Resources Canada Ltd., and S.M. Farouq Ali, U. of Alberta

SPE Members

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This paper was prepared for presentation at the SPE California Regional Meeting held in Long Beach, California, March 23-25, 1988.

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ABSTRACT

In designing steamfloods for thick formations, usually steam quality is assumed to be uniform over the formation face, even if multiple offtake points are present. This can lead to errors in steamflood oil recovery predictions. This paper addresses this question, and examines, first, the effect of multiple offtakes on steam quality and pressure, and second, the effect of variable vs. uniform steam pressure and quality on steamflood recovery predictions.

A wellbore model was developed, which accounts for steam pressure, quality, and flow regime variation, and the added feature of multiple offtake of the steam stream. The model was used to examine a variety of steam injection situations, with steam offtake at a halfway point. Effects of steam splitting on steam quality and pressure was examined for various wellhead pressures and injection rates. The wellbore simulator thus developed was then coupled with a three-dimensional steamflood simulator, to study steam injection performance in formations of various thicknesses, when steam is divided into two streams.

The results show that if the wellbore steam quality variation is not allowed significant errors in the predicted steamflood recovery can result. A number of examples are presented, showing discrepancies as large as 50%.

INTRODUCTION

Steam injection into multiple sands often utilizes a single tubing with steam distributors of appropriate design. The sands may be distinct, with a shale or other impermeable layer in between, or they may be in communication, essentially forming a single interval. In either case, steam injection rate, pressure and, in particular, quality, at each offtake point will differ, and may vary with time depending on the steam intake of each layer. If the steam offtake rates are the same at several points along the tubing, then one would expect the steam quality to decline with depth, the lower strata receiving steam of quality higher than that of steam at the upper layers. This problem was noted by Elson (1), who reported a laboratory investigation simulating wet steam by means of an air-water mixture, with offtakes at three points. Steam quality was found to decline from the uppermost

to the lowermost point; in one case the qualities at the three points were 88, 87, and 24%. Hong and Griston (2) discussed another aspect of the problem of steam injection into multiple sands, giving a comparison of injection down a single tubing with limited entry outlets, injection down a concentric tubing, and injection down a parallel tubing. They did not give results for the first case, but it was indicated that more control could be exercised in the other two injection schemes. A problem of a different type is posed by segregation of steam condensate, if any, in the wellbore. The presence of a fluid in the wellbore would influence steam rate and quality over the interval. Hong and Millhone (3) investigated this effect in the case of water injection wells.

At the present time, relatively little data is available on downhole steam quality measurements, although impressive progress has been made in this direction. Thus, much reliance must be placed on calculated values of steam quality. Although in larger diameter casings, concentric or parallel steam injection strings can be employed, in smaller casings, a single tubing may have to be equipped with distributors to inject steam at several points. This paper addresses this problem.

OBJECTIVES OF THIS STUDY

The main objectives of this theoretical investigation are to develop a wellbore model designed for multiple offtake of steam, and to use this model to examine the steam quality and pressure variations at two points, each receiving one-half of the total steam flow, as a function of time. A secondary objective is to determine oil recovery from a steamflood in a thick formation, using time-varying steam qualities at the two injection points, and compare it with the recovery for a uniform steam quality at the two points. It is believed that the results would be of value in showing the range of error caused by the latter simpler assumption.

WELLBORE STEAM FLOW MODEL

Formulation

The wellbore model developed for this study was designed to predict steam pressure (temperature), quality, and heat loss as functions of depth and time. The sand face steam pressure and

quality were then input into the steamflood simulator, as functions of time. The model is an improved version of an earlier model (4).

The system to be modeled consists of three parts: (i) the fluid flow conduit, tubing, or casing-tubing annulus, (ii) casing-tubing annulus, casing wall, and the cement sheath, and (iii) the formation surrounding the wellbore. Within the conduit, steady, two-phase flow of water and steam is assumed. This is described by combining a two-phase mass balance with a momentum balance, which is as follows (the vertical coordinate z is taken to be positive in the downward direction):

$$144 \frac{dp}{dz} - \rho_m \frac{g}{g_c} + \rho_m \frac{dW_f}{dz} + \frac{\rho_m v_m}{g_c} \frac{dv_m}{dz} = 0$$

The subscript m in the above equation refers to the steam-water mixture. The pressure gradient is given by

$$\frac{dp}{dz} = \frac{1}{144} \left(\frac{\rho_m \frac{dz}{dz} - \tau_f}{1 - \gamma_a} \right),$$

where γ_a is defined in the manner of Orkiszewski (4).

$$\gamma_a = \frac{w q_s}{144 A^2 g_c \rho}$$

Next, an energy balance is written for the flow under consideration, which is as follows:

$$\frac{\dot{Q}}{3600} + w \frac{d}{dz} \left(h_m + \frac{v_m^2}{2g_c J_c} - \frac{g}{g_c J_c} z \right) = 0,$$

where the enthalpy h_m refers to a two-phase steam-water mixture. The enthalpies of saturated water and steam were calculated from suitable equations. Using these equations, and allowing for heat flow from the tubing to the cement sheath given by

$$\dot{Q} = 2\pi r_{12} U_{12} (T - T_{12m}),$$

the energy balance equation takes the form:

$$C_1 \frac{dT_f}{dz} + C_2 f_{12} + C_3 = 0.$$

Here U_{12} represents the net resistance to heat flow offered by the flowing fluid, tubing, insulation, annulus fluid, casing wall and the cement sheath. The coefficients C_1 , C_2 , and C_3 are functions of pressure and the formation temperature given by

$$\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial T_f}{\partial r} \right) + \frac{\partial^2 T_f}{\partial z^2} = \frac{1}{\alpha} \frac{\partial T_f}{\partial t},$$

where T_f is the temperature of the surrounding formation and α is thermal diffusivity. This equation was solved, employing an r, z -grid. Previously, various authors have used the approximation to the Ei-function to estimate the temperatures around the wellbore, and thus derive the heat loss rate. Suitable boundary and initial conditions for solving the above equations are:

Initial Condition

$$T_f = T_a + \gamma z \quad \text{at } t = 0$$

Boundary Conditions

$$T_f = T_a \quad \text{at } z = 0$$

$$T_f = T_R \quad \text{at } z = Z$$

$$\dot{Q} = -2\pi r k_{12} \frac{\partial T_f}{\partial r} \quad \text{at } r = r_{12m}$$

$$\frac{\partial T_f}{\partial r} = 0 \quad \text{at } r = \infty$$

The flow regime prevailing in the tubing was treated using the correlations of Gould et al. (5), Chierici et al. (6), Duns and Ros (7), and Beggs and Brill (8), for bubble/plug, slug/froth, transition and mist flow.

The solution scheme used consisted in the simultaneous solution of the mass-momentum and energy balances, using a Runge-Kutta scheme, and solution of the implicit finite difference form of the radial heat conduction equation. The two sets of solutions were coupled iteratively. The overall solution procedure was stable, and the residuals were acceptably small.

DISCUSSION OF THE RESULTS

The aforesaid model was used to compute steam pressure and quality at two offtake points in the tubing, for a given set of conditions, viz. wellhead pressure, quality, and injection rate. The well depth was assumed to be 1500 ft, with one-half of the steam taken off at 1200 ft, for a 300 ft thick formation. Results for this case are given in detail. Other cases considered for steamflood simulations included formation thicknesses of 50, 100, 150, and 200 ft, again with two offtake points. Any number of offtake points can be treated by the model, but the case of two points illustrates the problem under consideration. The conditions used for the wellbore runs are listed in Table 1.

Effect of Steam Injection Rate and Flow Splitting on Steam Quality

Seventy-two runs were carried out for wellbore steam flow, half for no flow splitting, the other half for flow splitting. The results are listed in Tables 2 and 3, for wellhead steam pressures of 750 and 1500 psia, respectively. Figures 1 and 2 show the results for wellhead pressure of 750 psia, at 100 and 1100 days. At long times, the curves become invariant. In each figure, quality is plotted for steam injection rates of 600, 1200, and 1800 B/D (cold water equivalent). For each rate, there are two branches, one for zero offtake, and the other one for one-half steam offtake at 1200 ft. It is seen that the steam quality below the point of offtake is considerably lower than that in the absence of offtake, i.e. a single injection point. Furthermore, the relative quality drop becomes smaller as the steam injection rate increases. The plots for different times (e.g. 100 and 1100 days) show that this trend persists, however, steam quality at all points increases with time. The reason for this behaviour is that when steam is taken off at a particular point in the wellbore, the remaining steam flows at a reduced velocity (the flow regime may alter as a result), with approximately the same temperature. Thus the heat loss rate, which is dependent on temperature is nearly the same, and it now acts on a reduced steam flow rate, resulting in a sizeable quality drop. The situation is more complex, because steam pressure is also changing, causing a change in temperature, but this effect is not as important as the change in the steam flow, i.e. heat flow rate.

It can be expected that at higher steam flow rates, the relative heat flow is increased, and hence the above effects become less important, as Figs. 1 and 2 show. It can be concluded that the steam quality is likely to drop below the point of offtake in a multiple layer steam injection well. The amount of drop will depend on the steam injection rate, steam offtake rate, and steam pressure. Other variables not examined in this work are: the type of well completion, heat loss reduction method used, characteristics of the surrounding rocks, and the aforementioned effect of a fluid level in the wellbore, which would tend to restrict uniform distribution of steam over the injection interval.

Effect of Steam Injection Rate and Flow Splitting on Steam Pressure

Figures 3 and 4 show plots of steam pressure versus depth, for times of 100 and 1100 days, respectively. In each case, three

curves are shown for steam injection rates of 600, 1200, and 1800 B/D, as before. Each curve has two branches, one corresponding to zero offtake, the other one corresponding to an offtake rate that is one-half of the steam rate. It is seen that in all cases, the steam pressures below the offtake point (1200 ft) are higher than those in the absence of offtake. This is so because steam quality decreases below the offtake point (as shown in the previous section), leading to an increase in the hydrostatic head, which causes an increase in steam pressure. This is further helped by the reduced frictional pressure drop due to the reduced velocity of steam below the offtake point. This effect becomes less important as the steam injection rate increases. In an actual multilayer injection operation, the situation would be more complex than the one described here. The increased steam pressure expected below the offtake point will lead to an increase in the steam injection rate below the offtake point with time. As a result, it is possible that the steam flow rate at the intermediate offtake point would continue to drop with time, and eventually reach some equilibrium value different from the design rate. A complicating feature affecting steam injectivity is the quality itself. It may be concluded that steam injection wells with multiple offtake points can be difficult to control as far as steam inflow into individual layers is concerned.

Figures 5 and 6 summarize the results for bottomhole (1500 ft) steam quality, for offtake at 1200 ft, and for the two steam injection pressures considered (750 and 1500 psia). Again it is seen that the bottomhole qualities are lower when there is steam offtake. But the difference between the curves for increasing steam injection rates, or increasing steam injection pressure, decreases for the reasons given above. It is evident that the effect of offtake examined here is important, and should be taken into account. Steam injection simulations carried out at the present time neglect steam quality changes in multilayer injection.

Temperature Distribution in the Surrounding Rock

A secondary feature of interest is the temperature distribution in the formation surrounding the wellbore, when multiple steam offtakes are employed. It is recalled that in the present work, the temperature distribution in the surrounding formation was calculated by the solution of the radial heat flow equation. It is thus expected that the temperature distribution in the formation will depend on the steam temperature in the wellbore. The temperature distribution was found to be relatively insensitive to offtake and depends more on the injection time. Figure 7 shows the temperature distribution at a depth of 1200 ft at two different times. The curves for zero or one-half offtake are virtually the same.

Effect of Varying Steam Pressure and Quality on Steamflood Response

Given a wellbore model, such as the one developed here, it is possible to carry out a wide variety of coupled wellbore-reservoir studies. Several runs of this type were conducted to illustrate the effect of time and depth dependent steam pressure and quality on oil recovery, as compared to oil recovery based upon uniform values. A steam injection simulator was developed for this purpose, and coupled with the wellbore model. The simulator is a three-phase, three-dimensional fully implicit black oil type steam model, and utilizes a direct solution procedure. It has been extensively tested for many types of steam injection processes, including cyclic steaming.

Figures 8 and 9 show the oil production histories for a steamflood in a 300 ft thick formation. The data used in the simulations is given in Table 4, and refers to the Aberfeldy reservoir in Saskatchewan, which is much thinner (36 ft), but has oil viscosity similar to that in many California reservoirs.

It is seen that the assumption of a uniform sand face steam pressure and quality leads to an oil recovery of 42% (Fig. 8), which is considerably higher than the value of 28% (Fig. 9), for the more realistic case of variable pressure and quality. The main reason is that in the variable case, wetter steam is being injected into the lower part of the formation. At the same time, the pressure is higher, and thus more hot condensate is going into the lower zone. This tends to promote early steam override, as the temperature and steam saturation distributions showed.

Figure 10 summarizes the results for two steam injection rates (600 and 1800 B/D) and several formation thicknesses (50 to 300 ft), for the two cases, viz. uniform steam quality over the entire interval, and steam splitting so that steam pressure and quality vary with time over the two halves of the formation. The oil recoveries shown are for the same amount of steam injected in terms of pore volume. It is seen that the oil recovery varies considerably between the two cases considered, i.e. uniform and varying steam conditions. For a given injection rate, the oil recovery differs more at the larger formation thicknesses, because of the greater variation in steam pressure and quality over thick intervals. Also, the difference in the oil recoveries for the two cases is smaller at the higher rate, because of the smaller drop in quality from the offtake point to the total depth. Although these results are for specific conditions, they do show the importance of steam pressure and quality in relation to oil recovery computations.

CONCLUSIONS

Within the framework of the present investigation, the following conclusions can be derived:

1. If steam is taken off an injection tubing at more than one point, the steam quality and pressure at the lower points will continue to drop. The extent of quality drop depends on the steam offtake rates, wellhead steam pressure and quality, injection rate and time. The steam pressure will tend to increase below the offtake point.
2. Assumption of a uniform, rather than varying, steam quality and pressure over the entire injection interval in steamflood simulations will tend to give optimistic oil recoveries. The discrepancy decreases for smaller formation thicknesses and for higher rates.

Nomenclature

- A = area, sq ft (m^2)
 f_s = steam quality, fraction
 g = acceleration due to gravity, ft/s² (m/s^2)
 g_c = gravitational constant, 32.17 ft-lbm/lbf-s² ($9.80665 m/s^2$)
 h = specific enthalpy, Btu/lbm (kJ/kg)
 p = pressure, psia (Pa)
 q_s = volumetric flow rate of steam, cu ft/s (m^3/s)
 $\dot{Q}$ = heat loss rate to surroundings, Btu/hr-ft (kW/m)
 r = radius, ft (m)
 t = time, hours (seconds)
 T = temperature, °F (K)
 T_f = formation temperature, °F
 U_{eq} = overall heat transfer coefficient, Btu/hr-sq ft-°F ($kW/m^2 \cdot K$)
 v = velocity, ft/s (m/s)
 w = mass flow rate, lbm/s (kg/s)
 W_f = irreducible friction losses
 z = vertical coordinate, positive downward, ft (m)

- α = thermal diffusivity of the earth,
 sq ft/hr (m^2/s)
 γ = geothermal gradient, °F/ft (K/m)
 γ_a = acceleration gradient, dimensionless
 ρ = density, lbm/cu ft (kg/m^3)
 τ_f = friction loss gradient, lbf/sq ft-ft (Pa/m)

Subscripts

- ce = casing exterior
 cem = cement
 ins = insulation
 m = mixture (steam/water)
 res = reservoir
 s = dry and saturated steam
 te = tubing exterior
 w = saturated water

ACKNOWLEDGMENTS

This work was carried out under a CANMET/Energy, Mines and Resources Canada contract. The technical assistance of Dr. Albert George is gratefully acknowledged.

Appreciation is expressed to Dr. G.S. Reddy, Husky Oil Operations Ltd., Calgary, for helpful discussions of this topic.

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SI Metric Conversion Factors

Btu	x 1.055 056	E+00	= kJ
°F	(°F-32)/1.8		= °C
ft	x 3.048*	E-01	= m
in.	x 2.54*	E+00	= cm
lbm	x 4.535 924	E-01	= kg
psia	x 6.894 757	E+00	= kPa
sq ft	x 9.290 304*	E-02	= m ²

*Conversion factor to mm.

Table 1

CONDITIONS USED FOR WELLBORE HEAT LOSS CALCULATIONS

Pressure at Surface	260.0 psia
Atmospheric Temperature	80.0°F
Grid Points in R-Direction	5
Ratio of Radius of Grid	2.5
Time Elapsed	30.0 days
Thermal Conductivity of Annulus	0.0263
Emissivity of Tubing	0.9000
Density of Annular Fluid	0.0360 lbm/ft ³
Tolerance of P	1.00 psia
Type of Flow	Production
Tubing Insulation	No
Type of Annular Fluid	Gas
Casing Size	10.000 inch
Tubing Size	8.000 inch
Tubing Relative Roughness	0.00023
Depth	1400.0 feet
Reservoir Temperature	108.0°F
Grid Points in Z-Direction	11
Delta	140.0 feet
Deletion	3.0 days
Thermal Conductivity of Cement	0.5000
Emissivity of Casing	0.9000
Viscosity of Annular Fluid	0.0664 lbm/ft-hr
Tolerance of Q	0.010
Borehole Slim	12.000 inch
Mass Flow Rate	550000.0 lb/hr
Geothermal Gradient	0.020 °F/ft
Thermal Conductivity of Earth	1.4000
Thermal Diffusivity of Earth	0.9600 ft ² /day
Specific Heat of Annular Fluids	0.2475 Btu/lb-°F
Tolerance of U	0.05

Table 2

WELLBORE STEAM FLOW RUNS SUMMARY
DEPTH 1600 FT: STEAM OFFTAKE AT 1500 FT:
OFFTAKE RATE ONE-HALF FLOW RATE
SURFACE QUALITY 0.90

Legend:						
RN : WB RUN NUMBER						
T : Time, Days						
SR : Steam Rate, lb/hr/Day						
IP : Inj. Pressure, psia						
OR : Offtake Rate, Bbl/Day						
SQ : Steam Quality, Free at 1600 FT						
SP : Steam Pressure, psia at 1600 FT						
RN	T	SR	IP	OR	SQ	SP
1	100	600	1500	360	0.3298	1799.85
2	200	600	1500	360	0.3454	1800.01
3	300	600	1500	360	0.3458	1800.02
4	400	600	1500	300	0.3458	1800.02
5	500	600	1500	300	0.3458	1800.02
6	600	600	1500	300	0.3458	1800.02
7	700	600	1500	300	0.3458	1800.02
8	800	1200	1500	400	0.3574	1731.56
9	900	1200	1500	400	0.3751	1731.06
10	1000	1200	1500	400	0.3753	1731.05
11	1100	1200	1500	400	0.3753	1731.05
12	1200	1200	1500	400	0.3753	1731.05
13	1300	1200	1500	400	0.3753	1731.05
14	1400	1200	1500	400	0.3753	1731.05
15	1500	1200	1500	400	0.3753	1731.05
16	1600	1200	1500	400	0.3753	1731.05
17	1700	1200	1500	400	0.3753	1731.05
18	1800	1200	1500	400	0.3753	1731.05
19	1900	1200	1500	400	0.3753	1731.05
20	2000	1200	1500	400	0.3753	1731.05
21	2100	1200	1500	400	0.3753	1731.05
22	2200	1200	1500	400	0.3753	1731.05
23	2300	1200	1500	400	0.3753	1731.05
24	2400	1200	1500	400	0.3753	1731.05
25	2500	1200	1500	400	0.3753	1731.05
26	2600	1200	1500	400	0.3753	1731.05
27	2700	1200	1500	400	0.3753	1731.05
28	2800	1200	1500	400	0.3753	1731.05
29	2900	1200	1500	400	0.3753	1731.05
30	3000	1200	1500	400	0.3753	1731.05
31	3100	1200	1500	400	0.3753	1731.05
32	3200	1200	1500	400	0.3753	1731.05
33	3300	1200	1500	400	0.3753	1731.05
34	3400	1200	1500	400	0.3753	1731.05
35	3500	1200	1500	400	0.3753	1731.05
36	3600	1200	1500	400	0.3753	1731.05

Table 3

WELLBORE STREAM FLOW RUNS SUMMARY
DEPTH 1495 FT. STEAM OFFTAKE AT 1560 FT.
OPTAKE RATE ONE-HALF FLOW RATE
SURFACE QUALITY 0.80

Legend:
RN : WB RUN NUMBER
T : Time, Days
SR : Steam Rate, Btu/Day
IP : Inj. Pressure, psi
OR : Offtake Rate, Btu/Day
SQ : Steam Quality, Fric at 1560 FT
SP : Steam Pressure, psi at 1560 FT

RN	T	SR	IP	OR	SQ	SP
37	100	600	750	300	0.4603	1000.17
38	300	600	750	300	0.4714	998.31
39	500	600	750	300	0.4710	998.28
40	700	600	750	300	0.4716	998.28
41	900	600	750	300	0.4716	998.28
42	1100	600	750	300	0.4716	998.28
43	1300	600	750	300	0.4716	998.28
44	1500	600	750	300	0.4716	998.28
45	1700	600	750	300	0.4716	998.28
46	1900	600	750	300	0.4716	998.28
47	2100	600	750	300	0.4716	998.28
48	2300	600	750	300	0.4716	998.28
49	2500	600	750	300	0.4716	998.28
50	2700	600	750	300	0.4716	998.28
51	2900	600	750	300	0.4716	998.28
52	3100	600	750	300	0.4716	998.28
53	3300	600	750	300	0.4716	998.28
54	3500	600	750	300	0.4716	998.28
55	3700	600	750	300	0.4716	998.28
56	3900	600	750	300	0.4716	998.28
57	4100	600	750	300	0.4716	998.28
58	4300	600	750	300	0.4716	998.28
59	4500	600	750	300	0.4716	998.28
60	4700	600	750	300	0.4716	998.28
61	4900	600	750	300	0.4716	998.28
62	5100	600	750	300	0.4716	998.28
63	5300	600	750	300	0.4716	998.28
64	5500	600	750	300	0.4716	998.28
65	5700	600	750	300	0.4716	998.28
66	5900	600	750	300	0.4716	998.28
67	6100	600	750	300	0.4716	998.28
68	6300	600	750	300	0.4716	998.28
69	6500	600	750	300	0.4716	998.28
70	6700	600	750	300	0.4716	998.28
71	6900	600	750	300	0.4716	998.28
72	7100	600	750	300	0.4716	998.28

Table 4

RESERVOIR DATA USED IN THE SIMULATIONS

Formation thickness, ft	50 to 300
Pattern	20 across five-spot
Formation permeabilities, darcy	k_x k_y k_z 2.0 2.0 0.4 to 2.0
Porosity, %	35
Reservoir pressure, psi	200
Reservoir temp, °F	74
Oil viscosity at reservoir temp, cp	1275
Water compressibility, psi ⁻¹	3×10^{-6}
Water thermal expansion coeff., °F ⁻¹	4.9×10^{-4}
Oil compressibility, psi ⁻¹	5×10^{-6}
Oil thermal expansion coeff., °F ⁻¹	5×10^{-4}
Rock compressibility, psi ⁻¹	1×10^{-4}
Formation thermal conductivity, Btu/hr-ft-°F	1.76
Overburden thermal conductivity, Btu/hr-ft-°F	1.47
Overburden density, lb/ft ³	165
Overburden specific heat, Btu/lb-°F	0.20
Overburden thermal diffusivity, ft ² /hr	0.04
S_{wc} , fraction	0.20
S_{or} , fraction	0.211
S_g , fraction	0.1

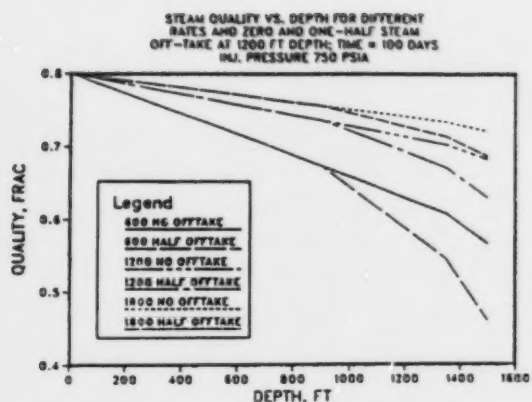


Figure 1. Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 100 days)

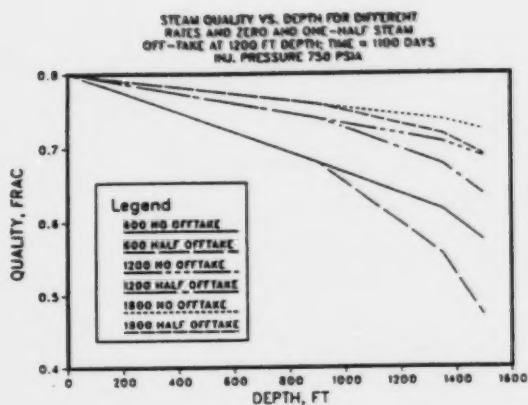


Figure 2. Wellbore Steam Quality for Zero and One-Half Offtakes (Time = 1100 days)

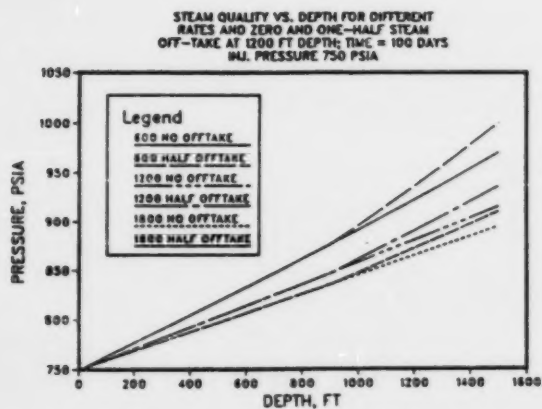


Figure 3. Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 100 days)

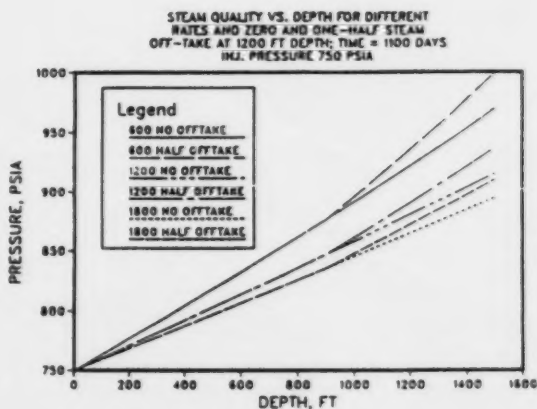


Figure 4. Wellbore Steam Pressure for Zero and One-Half Offtakes (Time = 1100 days)

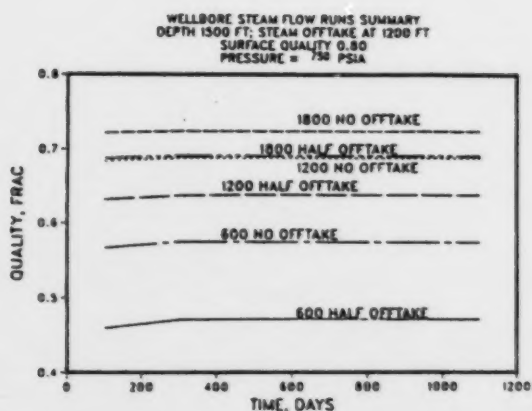


Figure 5. Wellbore Steam Quality vs. Time, for Surface Steam Pressure of 1200 psia

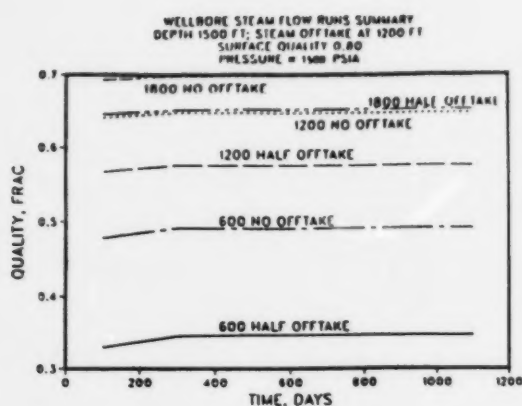


Figure 6. Wellbore Steam Quality vs. Time, for Surface Steam Pressure of 730 psia

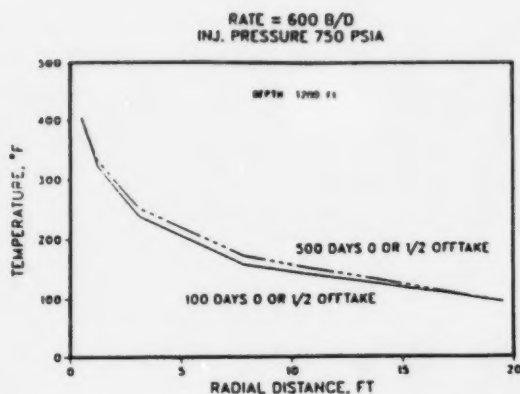


Figure 7. Temperature Distribution Around the Wellbore at 100 and 500 days

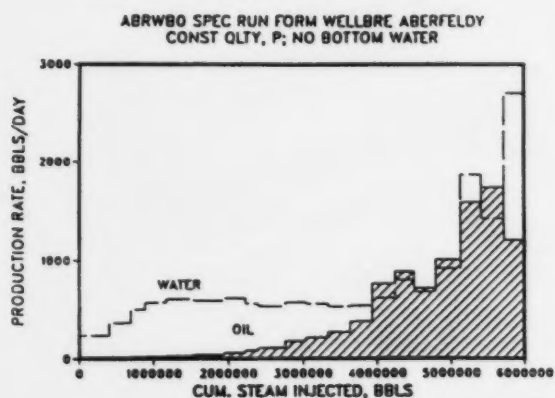


Figure 8. Production History for Steam Injection with a Uniform Steam Quality in the Wellbore, with Steam Offtake at Two Points

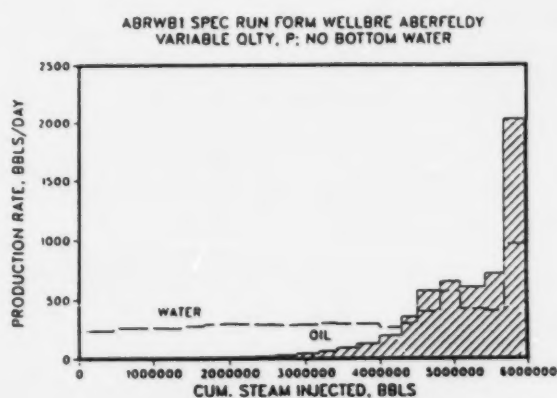
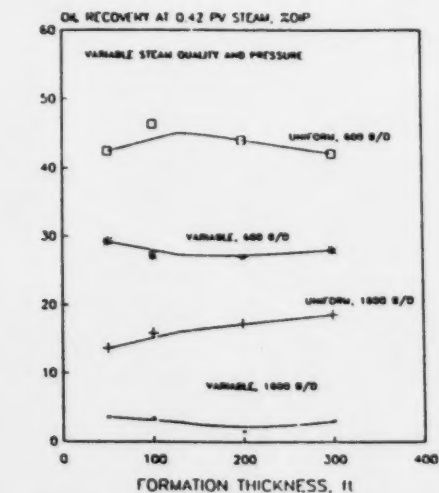


Figure 9. Production History for Steam Injection with a Variable Steam Quality in the Wellbore, with Steam Offtake at Two Points



Early steam breakthrough at high rates

Fig. 10. Effect of Formation Thickness and Steam Injection Rate on Oil Recovery with Steam Splitting.

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SCALED MODEL STUDIES OF SOLVENT-STEAM INJECTION, UNDER BOTTOM WATER CONDITIONS

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THIS PAPER IS TO BE PRESENTED AT THE 40th ANNUAL TECHNICAL MEETING OF THE PETROLEUM SOCIETY OF CIM HELD IN BANFF, MAY 28 TO 31, 1989. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE TECHNICAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

This paper discusses the results of an experimental study, using a scaled model for investigating the steamflood process under bottom water conditions. The main emphasis was on the use of a small amount of solvent with steam. Other strategies for improving steamflood efficiency were also examined. The prototype modeled is a heavy oil reservoir in Canada, where a steamflood is currently in progress.

In the experiments conducted, the emphasis was on a thin heavy oil formation, with underlying water, and in some cases, a gas cap. Such reservoirs are considered to be uneconomical for a conventional steamflood for reasons discussed. The purpose of using solvents in combination with steam is to increase steam injectivity in the oil zone, and create an initial flow path in the oil layer in order to divert the steam partially from the underlying water.

The experiments simulated bottom water thicknesses from one-tenth of the oil zone to one-fourth. Solvent slugs of the order of 10% pv were injected prior to steamflooding. The injection-production intervals were among the variables investigated. In several runs, the model was waterflooded prior to the solvent-steamflood, while in other runs, the initial oil saturation corresponded to irreducible water. It was found that, depending on the injection parameters (solvent slug size, rate, injection interval) and bottom water-to-oil zone thickness ratio, oil recovery varied from 11% to 34%. The experimental results were compared with those predicted by classical steam injection theories, with fair to good agreement in most cases.

INTRODUCTION

Many heavy oil reservoirs in Alberta and Saskatchewan contain a characteristic bottom water zone, which creates a serious field problem when a steamflood process is implemented. The presence of the underlying water zone causes a large amount of the injected steam to be diverted away from the target oil zone and into the bottom water layer. This lowers the steamflood thermal efficiency and therefore a steamflood is uneconomical in such reservoirs.

The main focus of this research was to incorporate solvent injection with a steamflood process in an attempt to improve oil recovery from thin heavy oil formations with underlying water zones. The purpose of the solvent slug injection prior to steamflooding was to create highly conductive flow channels in the oil zone for the steam to penetrate. The solvent channels formed in the oil region would aid in partially diverting the steam away from the detrimental bottom water zone, resulting in a greater volume of oil being heated, mobilized and consequently produced. The objective of the solvent-steamflood method was to guide the steam into the upper portion (oil layer) of the bottom water formation and keep the steam there as long as possible.

Other recovery schemes were investigated which also attempted to divert the steam away from the underlying water and into the oil region. The alternate methods considered were gas injection prior to a steamflood, or a solvent-steamflood, and steamflooding with a limited barrier at the oil/water contact, extending radially outward from the injection well.

BACKGROUND

Studies of Thin Bottom Water Reservoirs

Several studies have investigated oil recovery by steam injection into oil reservoirs containing bottom water. However, none of these studies dealt with thin reservoirs containing relatively thick bottom water regions and/or a gas zone. For this study a "thin heavy oil reservoir" was considered to be a heavy oil formation with a thickness of less than about 20 meters (65 feet). The prototype reservoir studied in this research is the thin, Aberfeldy reservoir which does not have a gas cap and a bottom water layer only exists in parts of the field. However, the versatility of the equipment used in this research allows one to create a bottom water layer and/or a gas cap in the model of the Aberfeldy reservoir.

Prats¹ modelled the Peace River reservoir, which is characterized by a large oil saturation (45%) in the bottom water layer. In the experiments, steam was injected into the bottom water, increasing the pressure in the reservoir in an attempt to heat the bottom water zone. This procedure enabled the overlying, highly viscous oil zone (65% oil saturation) to be mobilized by the heating effects of the bottom water zone. Due to the relatively high oil saturation in the water zone, the initial injection of steam into this zone resulted in a significant amount of oil being produced which increased the economic attractiveness of the recovery process. To further improve oil recovery, steam was injected directly into the oil zone once the oil saturation in this region was reduced to a predetermined value. The Wabasca reservoir examined by Huygen and Lowry² and the Cold Lake reservoir studied by Pursley³ were both characterized by relatively thin bottom water layers. These investigations therefore do not provide a reasonable representation of Aberfeldy type thin reservoirs. Other than the study performed by Doscher and Ghassemi⁴, little work has been done on steamflooding thin oil reservoirs such as the Aberfeldy.

A study by Kasraie and Farouq Ali⁵ further discussed the application of thermal recovery techniques to "marginal" heavy oil reservoirs. Such reservoirs are defined to have one or more of the following characteristics: thin formation (less than 6 metres), bottom water, gas cap or very high oil viscosity (over 10 Pa.s). Thermal recovery applications under such conditions depend strongly on the extent of bottom water, oil viscosity, vertical permeability, oil saturation and fluid injection rate. Vertical permeability was found to be an important factor in such reservoirs, since even a limited barrier between the oil and water zones would drastically reduce the tendency of the steam to channel down into the water layer. Therefore any shale breaks, silt zones or other heterogeneities at the base of the oil sand would serve to improve the oil recovery performance. Also the implementation of high temperature polymers, foams or additives, such as solvents, may also help to divert the steam away from the bottom water.

Dispersion and Diffusion of Solvents in a Porous Medium

A review of diffusion and dispersion in porous media has been presented by Perkins and Johnston⁶ and many other authors. Dispersion is defined as the mixing of solvent and oil in a porous medium caused by uneven fluid flow or concentration gradients resulting from fluid flow. Dispersion can occur in the longitudinal direction (direction of gross fluid flow) or transversely (perpendicular to gross fluid flow direction). Along with dispersion and diffusion, imbibition plays an important role in oil recovery during a solvent and/or steam injection process.

Incorporation of Solvent Injection into Thermal Recovery Methods

Alikhan and Farouq Ali⁸ investigated a recovery process, which incorporated miscible displacement with hot waterflooding. The recovery process involved introducing a small slug of a light hydrocarbon prior to the injection of one-half pore volume of hot water followed by a conventional cold waterflood. Results indicated that pre-injection of the light hydrocarbon slug preceding the waterflood led to a greater oil recovery than that obtained for a conventional waterflood. It was found that the overall oil recovery by this technique was dependent on oil viscosity, light hydrocarbon slug viscosity and the injection rate. The process was also found to be more effective when the reservoir had been previously waterflooded as opposed to a connate water saturation initially existing in the formation. Solvent recovery was found to be higher if a higher initial oil saturation existed, than if residual oil was present.

In studying the application of solvent slugs in thermal operations Farouq Ali⁹ investigated the change in phase behaviour characteristics due to an increase in temperature of the fluids involved in a solvent/steam recovery process. It was concluded that at elevated temperatures the overall phase behaviour of a typical alcohol-brine system would shift in such a direction as to make displacement of oil by alcohol more efficient. This could be achieved by injecting a small alcohol or solvent slug ahead of a steamflood. A study by Pirela and Farouq Ali¹⁰ investigated the ternary phase behaviour of solvent-oil-water systems at high temperatures. An increase in the temperature of the system resulted in an increase in the miscibility of the system, which was found to be advantageous from the standpoint of oil recovery.

Experiments conducted by Ozen and Farouq Ali¹¹ using linear, consolidated cores under isothermal conditions revealed that a steam drive could be an effective technique for recovering the residual oil after a waterflood. They also found that the introduction of a small slug of light hydrocarbon (naphtha) preceding steam injection improved the overall oil recovery.

Hernandez and Farouq Ali¹² used a one-dimensional model (linear) to examine the use of solvent injection to form a channel through the tar sand, connecting the injection and production wells prior to the injection of steam into the tar sand. Results of the study indicated that the injection of a solvent slug preceding steam injection created improved steam injectivity, leading to a higher overall recovery. It was also noted that the smaller solvent slugs aided in forming a channel into the tar sand for the steam, whereas the larger solvent slugs caused a permeability block which inhibited steam flow.

Snyder and Farouq Ali¹³ proposed the use of solvents as a means of developing flow channels in a tight tar sand to provide the initial flow paths for the injected steam. Specifically, the recovery efficiency of naphtha injection into a two-dimensional homogeneous tar sand pack at various injection rates, the effectiveness of gravity segregation and conductive heating in tar packs with a highly permeable channel were investigated. It was found that during steam injection the steam action was concentrated around the inlet and did not directly contact the bulk of the pack, and therefore naphtha injection prior to steam injection in a homogeneous pack was highly effective in opening a steam flow path. Once created, it allowed the steam to become more concentrated towards the production outlet resulting in improved overall oil recovery.

Farouq Ali and Abad¹⁴ studied the use of solvents in combination with steam using a three-dimensional elemental

model. They found that the type of solvent, the volume of solvent slug, and the placement of the solvent in the tar sand pack determined the bitumen recovery, and that smaller solvent slugs were more effective than larger slugs, with an optimum combination of solvent and steam slug.

A study performed by Farouq Ali, Look Yee, Cordero and Figueroa¹⁵ reported comparisons of base steamfloods and solvent-steamfloods showing that the solvent-steamfloods did improve oil recovery. It was also determined in the study that the injected solvent spread over a large area by viscous fingering if the injection rate was high, while if the rate was low the solvent essentially diffused into the bitumen and was largely confined to the immediate vicinity of the injection well.

In an economic evaluation of solvent/steam stimulation Doscher, Ershaghi, Herzberg and Gourene¹⁶ suggested that by reducing the viscosity of crude oil before contact with steam by use of a solvent, the overall steam requirement to achieve the same recovery without solvent might be reduced. The authors also suggested that solvent should be used in combination with steam to achieve specific advantages in a steam drive operation such as establishing or increasing conductivity between injection and production wells or increasing sweep efficiency.

Redford and McKay¹⁷ found that the use of a solvent in a steam process may reduce the residual saturation in the water-swept areas of the reservoir and thus improve the overall oil recovery. For solvents which are mixed hydrocarbons the more volatile additive (light ends) may act as a drive agent while the less volatile (heavier ends) one may act as a viscosity-reducing agent during the pressure depletion portion of the cycle which further improved recovery. Redford¹⁸ reported that the use of naphtha in combination with steam improved oil recovery by reducing bitumen viscosity and thereby improving recovery in the water-swept portions of the reservoir, thus making more efficient use of the drive energy provided by the steam.

A comprehensive study carried out by Alikhan and Farouq Ali⁸ investigated a combination of three different processes for the recovery of light and relatively viscous oils, using two approaches: injection of a slug of a light hydrocarbon miscible with the viscous oil, followed by the injection of hot water in one series of experiments, and a steam slug in another series each of which was then driven by water. Essentially the mechanism of the process was a combination of miscible displacement, hot waterflooding and steamflooding. The process was designed for a high thermal efficiency utilizing the maximum amount of heat injected. Conclusions drawn from the investigation suggested that the solvent slug injected prior to the hot water or steam slug in a sandpack improved oil recovery as compared to a straight hot water or steam slug run. The viscosity was further reduced by the heat from the injected hot water or steam slug, which led to an improvement in the mobility ratio and hence an improvement in the displacement efficiency. A large proportion of the light hydrocarbon slug was recovered by the steam distillation effect.

DISCUSSION OF THE RESULTS

Presentation of the Results

The emphasis of this study was on the use of a small amount of solvent with steam in an attempt to improve the steamflood efficiency. The purpose of using solvents in combination with steam was to increase steam injectivity in the oil zone, and create an initial flow path in the oil layer to divert the steam partially from the underlying water. Another series of experiments involved using other recovery strategies in an attempt to improve steamflood recoveries from reservoirs with thin bottom water zones.

Table 1 lists the pertinent values and results for all the experiments conducted in this investigation. The first group of runs consisted of base experiments which were compared with other experiments in order to observe the effects of different parameters such as solvent injection, solvent slug size, bottom water thickness, gas injection, injection-production interval locations and the use of alternative recovery schemes. These base experiments involved a continuous solvent flood in a homogeneous model, a solvent-steamflood in a homogeneous model and a steamflood with prior gas injection in a bottom model.

Steamflood vs. Solvent-Steamflood Process

During a steamflood, steam is injected into the injection well resulting in the creation of a steam zone which expands radially outward from the injector into the reservoir as more steam is injected. The hot condensate leaving the steam zone creates a hot waterflood in front of the steam zone. The steam zone, which is at an approximately constant temperature, is the most essential part of a steamflood. Oil in this region is highly mobilized by the heat and is displaced by the gas drive effect of steam. Also the thermal expansion of oil further mobilizes the oil, and steam distillation of lighter fractions of the oil helps to lower the oil saturation as well.

The mobilized oil is displaced and banked up ahead of the steam zone in the condensate region. Before the steam invades the oil region ahead of the steam zone, the undisturbed oil zone has already been swept by the cold condensate and then the hot condensate. In essence, the advancing steam zone contacts the same oil saturation, whether the formation is previously waterflooded or not. An illustration of the different regions that exist in the reservoir during a steamflood is provided in Figure 1.

Excellent areal coverage is usually obtained during a steamflood due to the gravity segregation of the steam which causes the steam to rise up through the formation. It can, however, limit vertical sweep in thick reservoirs.

The efficiency of a steamflood process is strongly dependent on formation thickness, steam quality, steam temperature and the presence of bottom water, since these factors determine the rate of growth of the steam zone. The presence of a bottom water layer in a thin heavy oil formation is undesirable since it provides a highly conductive flow path for the injected steam to underdrive the oil layer. This lowers the thermal efficiency of a steamflood because a majority of the steam's heat is scavenged by the underlying water.

The solvent-steamflood process is quite similar in nature to a steamflood except that a small slug of solvent is injected into the formation prior to steamflooding. The injected solvent channels directly into the oil region which forms an initial flow path for the steam. Therefore the heating effect of the steam can be more effectively utilized to mobilize and displace the oil in the reservoir. A schematic diagram of the solvent-steamflood process is given in Figure 2.

Thin heavy oil formations, with underlying water are considered to be uneconomic for a conventional steamflood for reasons discussed previously. Therefore the purpose of using solvents in combination with a steamflood is to improve steam injectivity in the oil zone, and create an initial flow path in the oil layer in order to divert the steam partially from the underlying water.

Typical Steamflood History in a Bottom Water Reservoir

To obtain a better understanding of the production history of a typical steamflood in a bottom water formation, consider Run 39, which consisted of a steamflood in a bottom water

model. In this run, the bottom water layer thickness was 12.5% of the gross model thickness, i.e. one-eighth of the model thickness.

Results of Run 39 suggested that steam preferentially flowed underneath the oil layer into the more conductive bottom water region due to lower steam injectivity of the oil layer above. Therefore, a majority of the steam heat was channelled into the underlying water zone, which inhibited the formation of a pronounced steam zone and oil bank in the model, and resulted in an unstable steam displacement of the oil and thus a poor oil recovery. The results of this run enabled one to achieve a better idea of what to expect during a continuous steamflood of a bottom water formation.

Base Experiments for Comparison Purposes

A range of base experiments were carried out during the research. The data collected from these base runs were used to determine the injection properties of the solvent in the oil-saturated model. The results of the base experiments were also compared with later experiments to determine the effects of solvent injection rate, solvent slug size, bottom water thickness, gas injection, injection-production interval location and a physical barrier on oil recovery, and thermal efficiency of a steamflood process implemented in a thin heavy oil formation, with underlying water.

Continuous Solvent Flood

Run 40 involved flooding a oil-saturated, homogeneous model with the chosen solvent (Heavy Virgin Naphtha). This first base run was a continuous solvent flood in the homogeneous (i.e. no bottom water) model. The intention of the solvent flood was to estimate the injection behaviour of the solvent in the homogeneous model during the experiment. It appeared that the solvent channelled through the oil immediately upon injection and continued to do so throughout the experiment. This type of injection behaviour of the solvent was desirable in the context of a steamflood, because the solvent channels formed would aid in increasing the injectivity of steam into the oil during a steam injection process. The higher steam injectivity could allow a steam injection process to be more thermally efficient since less of the heat would be lost to such heat sinks as overburden, underburden, adjacent formations and bottom water zones. Therefore the injected steam could be utilized more effectively in mobilizing and displacing the in-place oil.

Solvent-Steamflood

Runs 44, 45 and 46 involved injecting a small solvent slug into an oil-saturated, homogeneous model prior to a continuous steamflood. The purpose of the solvent slug prior to steam injection was to create solvent channels into the oil region through which the injected steam could more easily penetrate and thus, more efficiently mobilize the oil. Results indicated that more oil was mobilized and displaced, therefore a larger oil bank (actually solvent and oil) formed and a more stable steam displacement resulted. The greater stability of the steam injection process resulted in a prolonged time until steam breakthrough and an improved overall oil recovery.

The solvent-steamflood process did not appear to be as economically attractive as a conventional steamflood performed in a homogeneous model. However, in the case of a heavy oil formation with bottom water and displaying a very low steam injectivity the implementation of solvent injection would help to raise steam injectivity. This would make steam penetration more extensive in the oil and therefore increase recovery compared to a conventional steamflood.

Effect of Solvent Slug Size on Oil Recovery by a Steamflood

It was desired to determine the effect of solvent slug size on oil recovery from a solvent-steamflood process. By determining the effect of solvent slug size, an optimal slug size might be estimated. As reported by Alikhan¹⁹ the use of a 10% solvent slug prior to steam injection provided the highest oil recovery compared to the 5% and 15% solvent slug runs. A comparison plot (Figure 3) of the recovery curves for the three experiments indicates that Run 45 had the best recovery with Run 67 second and Run 66 having the lowest recovery. From the results of the three experiments it appeared that the 10% solvent slug run allowed a more stable displacement to occur in the model and thus a greater recovery. Run 45 (10% slug) achieved the optimal balance between oil viscosity reduction and channelling, which means that some of the oil does not contact the solvent. In the case of the 5% solvent slug experiment, less solvent channelling existed in the oil, thus less extensive steam penetration of the oil, consequently less oil was mobilized. For the 15% solvent slug run the larger solvent slug used created larger solvent channels in the model which allowed the steam to flow more directly from the injection to production wells and therefore more of the steam was partially diverted away from heating the oil than in Run 45. It was concluded from the results of Runs 66, 67 and 45 that there exists an optimal slug size of approximately 10% of the model pore volume which maximizes the oil recovered by a solvent-steamflood process.

Effect of Bottom Water Thickness on Solvent-Steamflood Response

The purpose of the initial solvent injection into the oil layer prior to steamflooding was to create a pathway in the oil layer for the steam to follow in an attempt to improve the oil recovery compared to conventionally steamflooding a bottom water formation.

Runs 49, 50, 51, 53 and 54 all involved injecting 0.10 pore volume of solvent (Heavy Virgin Naphtha) followed by a continuous steamflood of a model containing a bottom water layer. The only difference between the five bottom water experiments was that the bottom water thickness varied for each run. Bottom water thickness was altered in each run so as to investigate its effect on the oil recovery.

The bottom water thicknesses for Runs 49 (8.8% of gross model thickness), 50 (10.2% of gross model thickness) and 54 (12.2% of gross model thickness) were about the same, whereas Run 51 (26.2% of gross model thickness) and 53 (15.2% of gross model thickness) had much thicker bottom water layers. The injection well for the model was situated so to inject fluids into the upper portion of the model. This was to ensure that the solvent and steam would not flow directly into the bottom water layer and underdrive the oil immediately upon injection.

The overall oil recoveries for Runs 49 (23.3% OOIP), 50 (25.4% OOIP), 51 (14.3% OOIP), 53 (19.0% OOIP) and 54 (22.6% OOIP) illustrate that bottom water can significantly reduce the amount of oil recovered by a solvent-steamflood. The effect of the bottom water on solvent and steam injection resulted in a considerably lower oil recovery than that obtained with a solvent-steamflood implemented on a homogeneous reservoir. Results of Runs 49, 50, 51, 53 and 54 confirm that the use of a solvent slug assisted in improving the overall oil recovery by partially diverting the steam away from the bottom water and into the oil layer during the initial stages of the steamflood. It was also noted that the bottom water had a more detrimental effect on the overall oil recovery as it increased in thickness. Figure 4, a plot of oil recovery after two pore volumes injected versus bottom water thickness for the five experiments as well as Run 46 (solvent-steamflood without bottom water), demonstrates the

effect varying bottom water thickness has on overall oil recovery. It is seen that for thicknesses less than approximately 10% of the gross model thickness, the oil recovery due to the solvent-steamflood process is close to that obtained by solvent-steamfloods implemented in homogeneous models. For bottom water thicknesses greater than about 10% of the total model thickness the overall oil recovery of the solvent-steamflood process is greatly reduced. The experimental results suggest that the injection of a solvent slug prior to steamflooding a bottom water reservoir could improve the overall oil recovery up until a limiting bottom water thickness is reached. Based upon Figure 4, the limiting bottom water thickness is estimated to be somewhere between 25 and 30% of the total model thickness. It is concluded that as the bottom water thickness increases in the model the oil recovery is decreased until a limiting bottom water thickness is reached, above which the use of a solvent slug does not significantly improve the oil recovery.

One of the major objectives of this study was to investigate the use of solvents in combination with steam as a recovery method for marginal heavy oil reservoirs containing bottom water and/or a gas cap. Solvent injection into the oil layer during the initial period of the runs created a temporary preferential path for the steam to follow, preventing the steam from immediately channelling into the bottom water. The steam progressed through the oil layer for a short period of time until it finally moved downward and advanced through the bottom water section, leading to a drop in heating efficiency, and a severe drop in the overall oil recovery.

Comparison of the results of Runs 49, 50 and 54 with previous continuous steamfloods (Runs 32, 33 & 39) carried out with similar bottom water (BW) thicknesses, revealed that the solvent slug injection prior to steamflooding partially alleviated the effect of bottom water and resulted in improved oil recovery. Due to partial diversion of the steam into the solvent channels in the oil region the steam displacement achieved was more stable, causing a delayed and more pronounced steam breakthrough to occur at the production well. In the case of a conventional steamflood, the bottom water had a greater and more immediate effect on steam displacement resulting in a much less stable displacement. This led to earlier and less distinct steam breakthrough at the producer. Oil recovery results for Runs 32 (BW=2.3%), 33 (BW=4.0%) and 39 (BW=12.5%) were 22.8%, 22.9% and 16.8% of the original oil in place, respectively. These recoveries were appreciably less than the recoveries yielded by Runs 49 (23.3%), 50 (25.4%), 53 (19.0%) and 54 (22.6%). In the case of Run 51, there did not seem to be an improvement in the oil recovery compared to the Runs 32, 33 and 39. Because of the extensive bottom water layer in Run 51 the steam was not able to flow through the oil layer for as long as in Runs 49, 50, 53 and 54 resulting in a considerable decline in the oil recovery of Run 51. Comparing the results of the two different types of experiments (i.e. steamflood vs. solvent-steamflood) revealed that the solvent-steamflood does exhibit an improved oil recovery capability from bottom water formations in relation to a conventional steamflood. A cross plot of the recovery curves for Runs 39 and 54 is provided in Figure 5 which compares the effectiveness of a solvent-steamflood process as opposed to a steamflood in similar bottom water formations. The difference in the initial behaviour of these two curves demonstrates the effectiveness of the solvent slug. The recovery curve for Run 54 in the primary stages of the run rises sharply compared to the recovery curve of Run 39. This was due to solvent channelling in Run 54 allowing the steam to penetrate the oil zone more easily, which increased the stability of the steam displacement of oil in the model, and resulted in more oil being mobilized and subsequently recovered. Figure 5 illustrates the increased oil recovery potential of the solvent-steamflood process over a conventional steamflood in bottom water formations.

It is concluded from the results of Runs 32, 33, 39, 49, 50, 51, 53 and 54 that the solvent slug assisted in improving the overall oil recovery in bottom water formations by partially diverting the steam away from the bottom water zone during the initial stages of the steamflood.

Role of Gas Injection in Steamflooding

Gas Injection with Solvent and Steam Injection

By injecting a small value of inert gas before performing a solvent-steamflood it is believed that a flow channel can be created which would divert the injected solvent and steam away from the bottom water region and into the oil zone. The process of gas injection in combination with a solvent-steamflood was first performed in a homogeneous model. Runs 55 and 56 consisted of creating a gas cap in a homogeneous model prior to a solvent-steamflood which used a 10% pore volume slug of solvent. The initial gas saturation in the model for the two runs was 0.6%.

Gas Injection Prior to Solvent and Steam Injection with Bottom Water

Runs 58, 59 and 62 involved performing a solvent-steamflood on a bottom water/gas cap reservoir. The bottom water thicknesses for Runs 58, 59 and 62 were 9.8%, 13.6% and 12.0% of the gross model thickness, respectively, and the initial gas saturations were 0.6% (Run 58), 0.6% (Run 59) and 0.3% (Run 62), averaged over the entire zone. It is estimated that the gas segregated into a thin layer above the oil zone, given a critical gas saturation of zero, in the time involved.

Figure 6 provides a comparison of the recovery curves for a solvent-steamflood (Run 50) and a solvent-steamflood with previous gas injection (Run 58) in bottom water models. The bottom water thicknesses were 10.2% and 9.8%, respectively in these runs. It is evident from Figure 6 that Run 50 (solvent-steamflood) achieved a considerably greater oil recovery than Run 58 (gas injection prior to solvent-steamflood). The main difference between the curves occurred during the initial stages of the two experiments. Run 50 had a more drastic initial increase in recovery (25.4% OOIP) compared to Run 58 (18.2% OOIP) due to the solvent and oil more effectively penetrating the oil zone and creating more stable steam displacement of oil during Run 50. Run 58 had a less pronounced solvent and oil invasion in the oil region since more solvent and oil flowed over top of the oil zone through the gas saturation channel formed by the previous gas injection. Steam breakthrough was earlier and less distinct for Run 58 due to the existence of a less stable displacement of oil caused by the gas channel.

A gas cap in a reservoir can be helpful or detrimental to the effectiveness of a steam injection process depending on certain characteristics of the reservoir such as heat loss, reservoir thickness, bottom water thickness and the gas cap size. During the steamflood of a bottom water reservoir the gas cap allowed the steam to remain in the upper portion of the formation away from the bottom water, thus heating and mobilizing the inplace oil from above. How effectively the oil was mobilized from above depends on the magnitude of the heat lost to the overburden, adjacent formations and the bottom water zone. However, in the case of the solvent-steamflood process the gas cap enabled the solvent to flow over the top of the oil zone. Overriding of the oil by the solvent caused fewer flow channels to form in the oil layer, which hindered the penetration of the oil layer by steam. Consequently, less oil was mobilized by the steam resulting in a decline in the overall recovery of a solvent-steamflood process as compared to its implementation in a heavy oil reservoir with bottom water but no gas cap or gas channel.

Effect of Injection-Production Interval Locations

The effect of injection-production interval locations on the success of the solvent-steamflood process in bottom water reservoirs was found to be very important. By optimizing the injection-production interval positions the injected solvent and steam could be utilized effectively to recover the in-place oil.

A comparison of the recovery curves from the two experiments (Runs 49 and 50), provided in Figure 7, indicates that the most effective injection-production intervals appeared to be those used in Run 50 where injection was into the upper half and production was from the entire model thickness. The injection interval location for Run 50 permitted more efficient use of the injected solvent and steam, by directing these fluids into the oil zone and away from the bottom water, thus yielding a higher overall oil recovery. However, for Run 49, more solvent and steam were lost to the underlying water zone, making this solvent-steamflood process less efficient than the solvent-steamflood conducted in Run 50.

Effectiveness of Waterflooding Prior to Solvent and Steam Injection

Another objective of the research conducted was to determine the effectiveness of the solvent-steamflood process as an enhanced recovery technique. In Runs 47 and 48 a solvent-steamflood was conducted following a waterflood of a homogeneous model.

The overall oil recoveries for Runs 47 (33.5% OOIP) and 48 (35.5%) were higher than the recoveries obtained from the conventional steamfloods of the homogeneous model performed in Runs 26 (31.8%) and 27 (32.2%) as reported by Proctor, George and Farouq Ali²⁰. The recoveries for the solvent-steamfloods of a homogeneous model (Runs 44 (27.1%), 45 (30.0%) and 46 (27.7%)) reported in this study also indicate that Runs 47 and 48 yielded a greater overall oil recovery. The oil recoveries for the waterflood cases (Runs 47 and 48) were higher because the solvent was able to blend with in-place oil more thoroughly than during the oil saturated experiments (Runs 26, 27, 44, 45 and 46). Alikhan¹⁹ also stated that for a high initial oil saturation the solvent slug is displaced as efficiently as the in-place oil, thus the advantage of using the solvent is partially lost and the oil recovery is diminished. However, for a waterflooded porous medium the solvent is able to mix more extensively with the oil allowing the injected steam to contact a higher saturation of the solvent slug material leading to improved oil recovery.

Comparing the oil recoveries for Runs 47 and 48 with those for the previous experiments using a homogeneous model, it was noted that Runs 47 and 48 yielded the highest oil recovery of all the experiments performed using a homogeneous model saturated with oil. The information obtained from Runs 47 and 48 agrees closely with the results recorded by Alikhan¹⁹. Performing solvent-steamfloods on waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery technique, but will depend strongly on the initial oil in-place.

Heat Flow Analysis

Several experiments were analyzed using the classical methods of Lauwerier (20) and Mandl and Volek (21). Lauwerier's method predicts the temperature as a function of area and time for the injection of a hot fluid (no latent heat). Given a steam injection rate, the temperatures were calculated using the areas enclosed by the measured isotherms. If the respective calculated and measured temperatures are in agreement, it is implied that the steam was present in the form of hot water (total

condensation). Computations for Run 26 showed that this was indeed so in the case of the bottom half of the formation thickness, i.e. the steam largely advanced in the upper part, and as it condensed, the condensate flowed near the base. The agreement between the calculated and measured temperatures was good at longer times (0.5 pv, or more, of steam injection). Table 2 shows the calculated and measured temperatures in the upper and lower halves of the formation thickness. Temperatures in the range of 60-70°C correspond to the steam temperature, while 3°C is the original formation temperature.

Steam zone volume was also calculated using the Mandl-Volek equation (21). For example, at 0.5 pv of steam injection, the steam zone volume was 22.2% of the bulk volume of the model. This is close to the steam zone volume based upon the Lauwerier analysis. Thus, given the measured temperature distribution, the classical methods can be used for determining the extents of the steam and hot water zones; even the lack of agreement with the measured data can provide useful information about the process.

CONCLUSIONS

Based upon the results the research the following conclusions were reached:

1. The solvent-steamflood process exhibits an improved oil recovery capability from a bottom water formation as compared a conventional steamflood in the same type of reservoir for an oil viscosity of about 1000 mPa-s. As the bottom water thickness increased in the model, the oil recovery decreased until a limiting bottom water thickness was reached. Above this value (between 25% and 30% of the total formation thickness), the use of a solvent did not significantly improve oil recovery. There seems to be an optimal solvent slug size of approximately 10% of the model pore volume which maximizes the amount of oil recovered by a solvent-steamflood process.
2. Gas injection prior to a solvent-steamflood of a bottom water formation tends to diminish solvent channelling in the oil, due to the solvent travelling over top of the oil zone, with less steam penetrating the oil layer, with a consequent drop in oil recovery.
3. Location of the injection interval in the upper portion of the formation (i.e. oil zone) permits more efficient use of the injected solvent and steam and increases oil recovery by directing the fluids into the oil zone and away from the bottom water layer, as compared to injection over the entire interval or into the bottom portion of the formation.
4. Conducting solvent-steamfloods of previous waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery scheme.
5. A comparison of the experimental results for a solvent-steamflood, conventional steamflood and gas injection prior to a solvent-steamflood, all conducted in a bottom water model, revealed that the solvent-steamflood technique yielded the highest oil recovery.

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Table 1: List of Experiments

Run No.	Model Type	Type of Process	Inj. & Prod. Intervals	Porosity (%)	Soi (%)	Swi (%)	Sgi (%)	Bottom Water (%)	Slug Size (% P.V.)	Cum. Rec. (%OOIP) *	Solv. Rec. (%) *	Cum. P.V. Injected
39	BWM	SF	IE - PU	37.1	86.0	14.0	---	12.5	---	16.8	---	1.78
40	HM	CSI	IE - PU	33.7	92.5	7.5	---	---	---	26.8	89.5	2.25
41	HM	USR	IE - PU	---	---	---	---	---	---	---	---	---
42	HM	USR	IE - PU	---	---	---	---	---	---	---	---	---
43	HM	USR	IE - PU	---	---	---	---	---	---	---	---	---
44	HM	SSF	IE - PU	33.7	92.9	7.1	---	---	10.0	27.1	70.4	2.33
45	HM	SSF	IE - PU	34.1	92.0	8.0	---	---	10.0	30.0	71.2	2.59
46	HM	SSF	IE - PU	38.7	80.9	19.1	---	---	10.0	27.7	33.1	2.07
47A	HM	WF	IE - PU	33.6	93.0	7.0	---	---	---	19.1	---	1.54
47B	HM	SSF	IE - PU	33.6	75.3	24.7	---	---	10.0	33.5	44.9	2.03
48A	HM	WF	IE - PU	33.4	92.7	7.3	---	---	---	19.8	---	1.69
48B	HM	SSF	IE - PU	33.4	74.3	25.7	---	---	10.0	33.5	58.9	2.25
49	BWM	SSF	IE - PU	37.0	86.7	13.3	---	8.8	10.0	23.3	84.6	2.13
50	BWM	SSF	IU - PE	35.8	91.2	8.8	---	10.2	10.0	25.4	88.5	2.26
51	BWM	SSF	IU - PE	37.7	66.9	33.1	---	26.2	10.0	14.3	40.8	2.05
52	BWM	USR	IU - PE	---	---	---	---	---	---	---	---	---
53	BWM	SSF	IU - PE	36.5	76.2	23.8	---	15.2	10.0	19.0	54.4	2.16
54	BWM	SSF	IU - PE	36.1	91.0	9.0	---	12.2	10.0	22.6	89.8	2.39
55	HM	GISSF	IU - PE	34.3	90.3	9.1	0.6	---	10.0	26.8	87.7	2.37
56	HM	GISSF	IU - PE	33.6	93.0	6.3	0.6	---	10.0	27.0	90.9	2.43
57	BWM	USR	IU - PE	---	---	---	---	---	---	---	---	---
58	BWM	GISSF	IU - PE	35.6	86.4	13.0	0.6	9.8	10.0	18.2	88.6	2.27

Table 1: Continued

Run No.	Model Type	Type of Process	Inj. & Prod. Intervals	Porosity (%)	Soi (%)	Swi (%)	Sgi (%)	Bottom Water (%)	Slug Size (% P.V.)	Cum. Rec. (%OOIP) *	Solv. Rec. (%) *	Cum. P.V. Injected
59	BWM	GISSF	IU - PE	35.7	85.3	14.1	0.6	13.6	10.0	24.7	96.7	2.30
60	BWM	GISF	IU - PE	35.9	76.3	23.4	0.3	17.6	---	13.6	---	2.31
61	BWM	GISF	IU - PE	36.0	83.5	16.2	0.4	12.1	---	19.5	---	2.30
62	BWM	GISSF	IU - PE	36.3	83.4	16.3	0.3	12.0	10.0	20.0	94.7	2.29
63	BWM	SFPBW	IU - PE	36.3	77.5	22.5	---	15.4	---	17.0	---	2.26
64	BWM	SFPBW	IU - PE	36.7	87.5	12.5	---	9.9	---	22.0	---	2.27
65	BWM	SSF	IU - PE	36.1	73.4	26.6	---	19.6	20.0	19.8	73.0	2.29
66	HM	SSF	IU - PE	33.5	93.3	6.7	---	---	5.0	24.2	91.4	2.59
67	HM	SSF	IU - PE	33.5	92.5	7.5	---	---	15.0	25.9	97.0	2.43

HM - Homogeneous Model

BWM - Bottom Water Model

SF - Continuous Steamflood

CSI - Continuous Solvent Injection

SF - Steamflood

SSF - Solvent-Steamflood

WF - Waterflood

GISF - Gas Injection Prior to Steamflood

GISSF - Gas Injection Prior to Solvent-Steamflood

SFPBW - Steamflood with Partial Bottom Water Barrier

USR - Unsuccessful Run

IU - Injection Into Upper Portion of Model

IE - Injection Over Entire Model Interval

PU - Production From Upper Portion of Model

PE - Production From Entire Model Interval

* - The Cumulative Oil and Solvent Recoveries listed in the table correspond to the Cumulative Pore Volume Injected which is provided in the last column of this table.

Table 2: Heat Flow Analysis of Model Using The Lawwerier Equation
(Experiment 26)

Portion of Model	Pore Volume Injected	Actual Conour Temp. (C)	Lawwerier Equation Temp. (C)	Portion of Model	Pore Volume Injected	Actual Conour Temp. (C)	Lawwerier Equation Temp. (C)
Upper Inj. Rate 1.5405 B/D	0.25	10	32.61	Upper Inj. Rate 1.5405 B/D	0.75	10	4.32
		20	50.65			20	47.02
		30	59.88			30	59.16
		40	62.63			40	64.04
		50	65.05			50	65.74
		60	66.63			60	66.99
		70	67.49			70	67.80
Lower Inj. Rate 0.5135 B/D	0.25	10	3.00	Lower Inj. Rate 0.5135 B/D	0.75	10	3.00
		20	3.00			20	3.00
		30	29.19			30	3.00
		40	46.59			40	3.00
		50	56.24			50	8.68
		60	62.92			60	45.69
		70	65.45			70	63.46
Upper Inj. Rate 1.5405 B/D	0.50	10	32.15	Upper Inj. Rate 1.5405 B/D	1.00	10	3.00
		20	49.30			20	38.74
		30	58.19			30	55.78
		40	62.20			40	63.47
		50	63.48			50	65.06
		60	65.09			60	66.29
		70	66.11			70	67.40
Lower Inj. Rate 0.5135 B/D	0.50	10	3.00	Lower Inj. Rate 0.5135 B/D	1.00	10	3.00
		20	3.00			20	3.00
		30	3.00			30	3.00
		40	3.00			40	3.00
		50	8.53			50	3.10
		60	48.44			60	11.81
		70	66.86			70	43.18

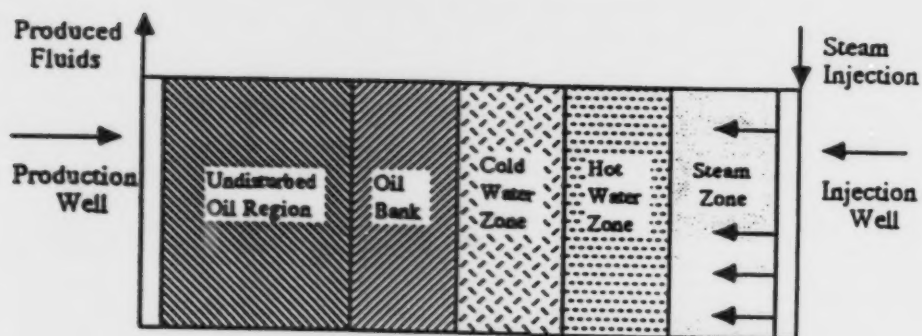


Figure 1 : Schematic Diagram of a Steamflood Process

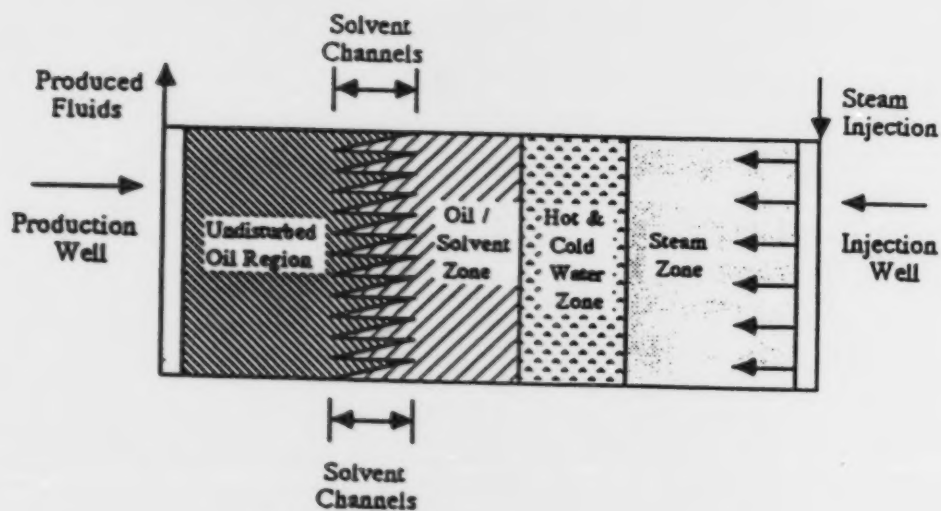


Figure 2 : Schematic Diagram of Solvent - Steamflood Process

Figure 3 : Comparison of the Effect of Solvent Slug Size on Solvent-Steamflood Recoveries for Runs 45, 66 & 67

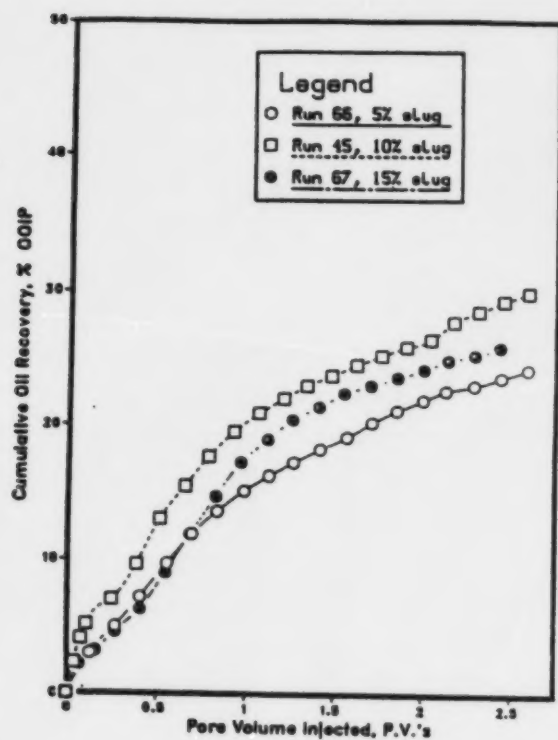


Figure 4 : Total Oil Recovery versus Bottom Water Thickness For Solvent-Steamfloods

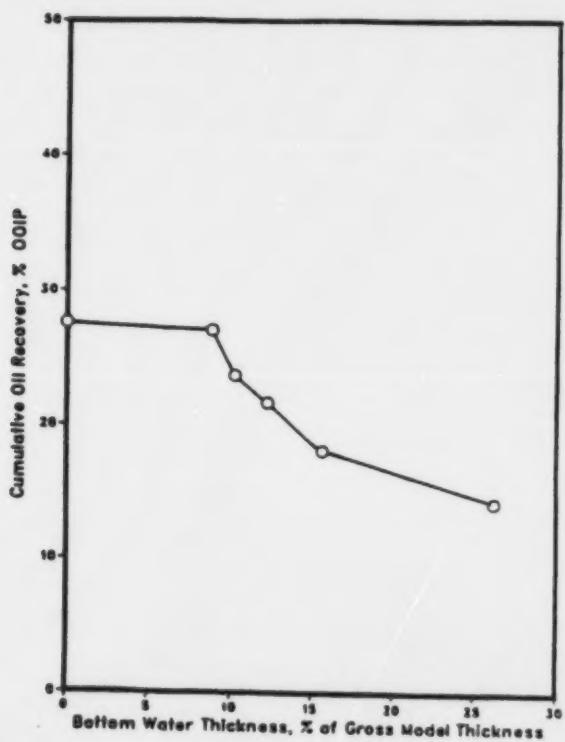


Figure 5 :Comparison of Steamflood Run 39 & Solvent-Steamflood Run 54 Recoveries Performed in a Bottom Water Model

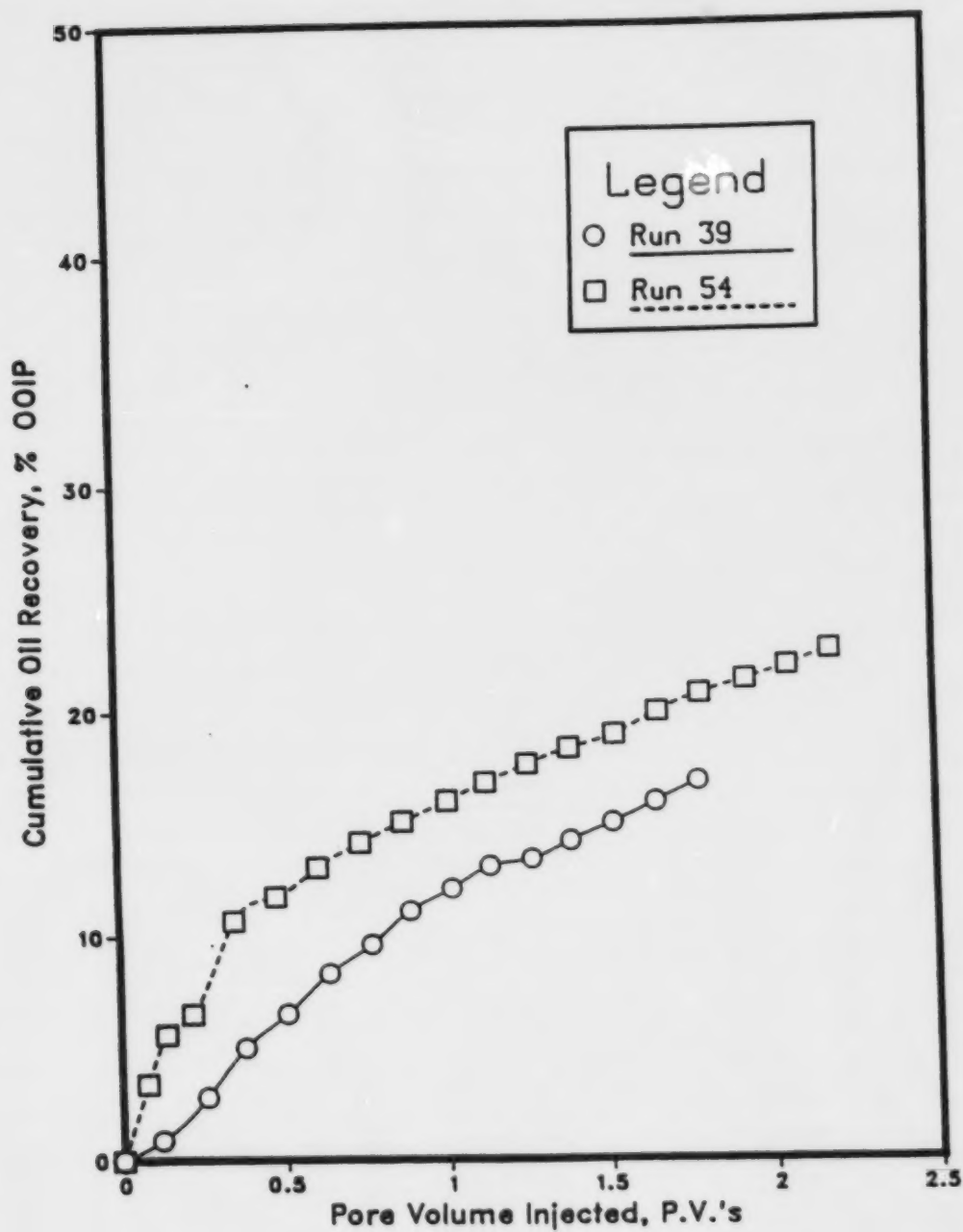


Figure 6 :Comparison of Solvent-Steamflood Run 50 & Gas Injection Prior to Solvent-Steamflood Run 58 Recoveries Performed In a Bottom Water Model

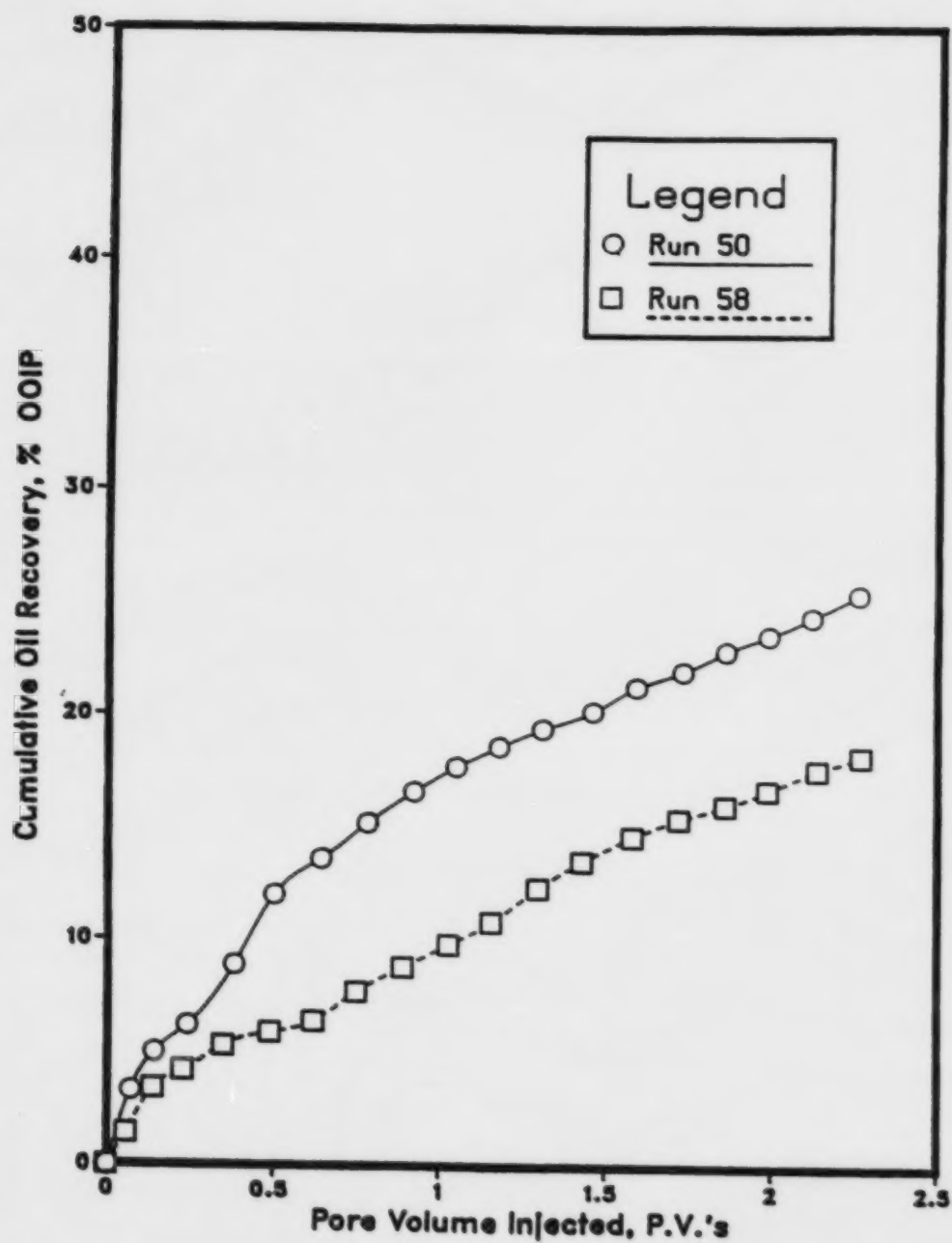
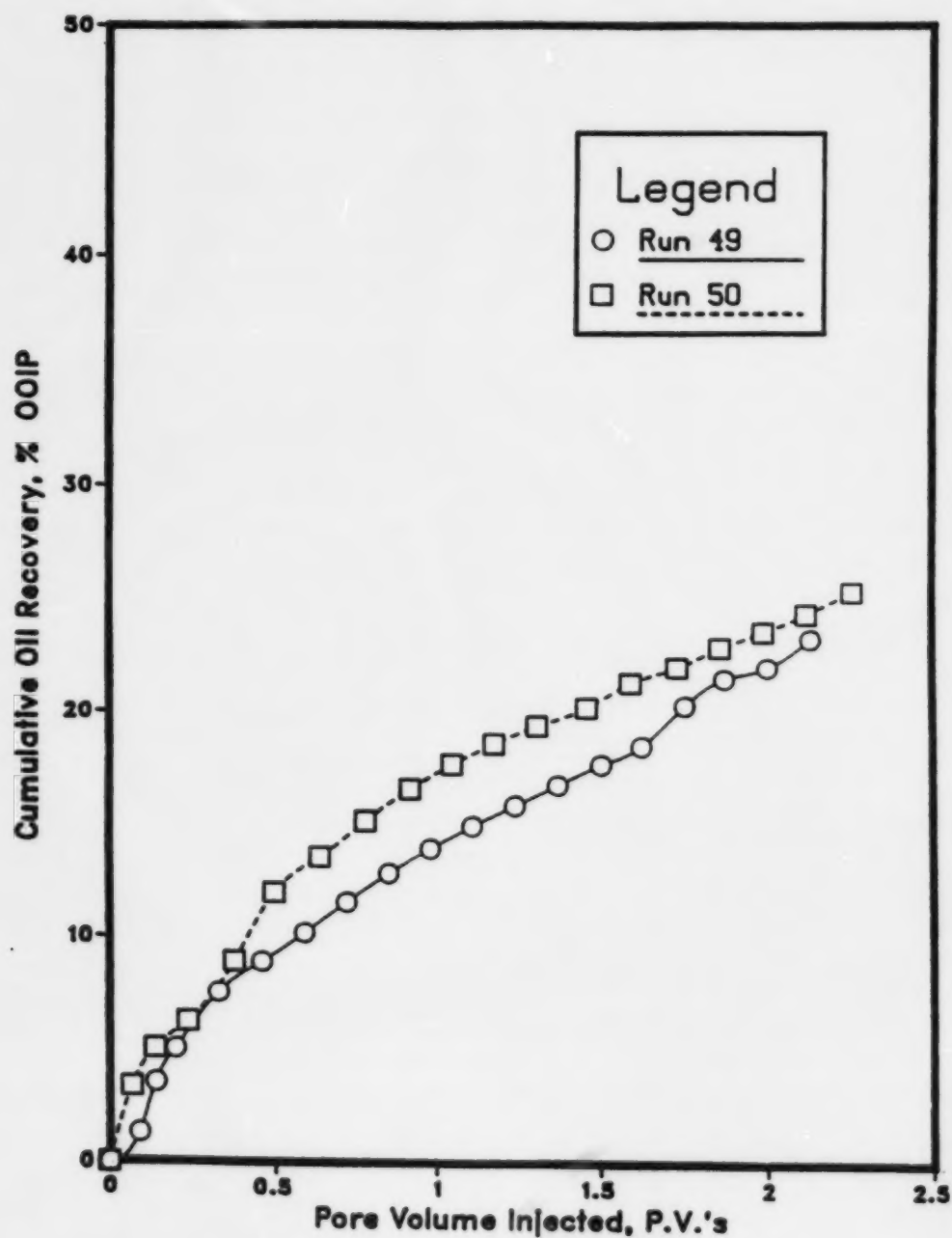


Figure 7 :Comparison of the Effect of Inj.-Prod. Interval Locations For Runs 49, Inj-Entire & Prod-Upper, & Run 50, Inj-Upper & Prod-Entire





SRM 3 164

SCALED MODEL STUDIES OF SOLVENT-STEAM INJECTION

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MARACAIBO, VENEZUELA, DEL 19-22 DE FEBRERO DE 1989

ABSTRACT

Results of an experimental study, using a scaled model for investigating the steamflood process under bottom water condition are discussed. The emphasis was on the use of a small amount of solvent with steam. Other strategies for improving steamflood efficiency were also examined. The reservoir modeled is a heavy oil reservoir in Canada where a steamflood has been operated.

In the experiments conducted, a thin oil-bearing formation was considered, with an underlying bottom water zone, and in some cases a gas zone. Such reservoirs are considered to be uneconomic for a conventional steamflood for reasons discussed in the paper. The purpose of using solvents in combination with steam is to increase steam injectivity in the steam zone, and create an initial flow path in the oil layer in order to divert the steam partially from the underlying water.

The experiments simulated bottom water thicknesses from one-tenth of the oil zone to one-fourth. Solvent slugs of the order of 10% pore volume of the oil zone were injected prior to steamflooding. The injection-production intervals were among the variables investigated. In several runs, the model was waterflooded prior to the solvent-steamflood, while in other runs, the initial oil saturation corresponded to irreducible water. It was found that depending on the injection parameters (solvent slug size, rate, injection interval) and the bottom water-to-oil zone thickness ratio, oil recovery varied from 11 to 34%. The experimental results were compared with those predicted by classical steam injection theories, with fair to good agreement in most cases. The usefulness and field application of the experimental results obtained is discussed.

INTRODUCTION

At the present time, steam injection processes account for the recovery of over one million barrels of heavy oil each day. The two

major types of steam injection techniques are cyclic steam stimulation and steamflooding. To-date, cyclic steaming is the only proven commercial heavy oil recovery scheme to be successful in recovering heavy oil from the Cold Lake oil sands formations. Steamflooding has been very successful in California heavy oil reservoirs, such as San Ardo, Kern River and Midway Sunset fields. Recently the steamflood process has been implemented in some Saskatchewan fields such as the Aberfeldy.

Many heavy oil reservoir in Alberta and Saskatchewan contain a characteristic bottom water zone, which creates a serious field problem when a steamflood process is implemented. The presence of the underlying water zone causes a large amount of the injected steam to be diverted away from the target oil zone and into the bottom water layer. This lowers the steamflood thermal efficiency and therefore steamflood is uneconomical in such reservoirs.

The main focus of this research was to incorporate solvent injection with a steamflood process in an attempt to improve oil recovery from thin heavy oil formations with underlying water zones. The purpose of the solvent slug injection prior to steamflooding was to create highly conductive flow channels in the oil zone for the steam to penetrate. It was thought that the solvent channels formed in the oil region would aid in partially diverting the steam away from the detrimental bottom water zone, resulting in a greater volume of oil being heated, mobilized and consequently produced. The objective of the solvent-steamflood method was to guide the steam into the upper portion (oil layer) of the bottom water formation and keep the steam there as long as possible.

Other recovery schemes were investigated which also attempted to divert the steam away from the underlying water and into the oil region. The alternate methods considered were gas injection prior to steamflood, or a solvent-steamflood, and steamflooding with a limited barrier at the oil/water contact, extending radially outward from the injection well.

BACKGROUND

Studies of Thin, Bottom Water Reservoirs

Several studies have investigated oil recovery by steam injection into oil reservoirs containing bottom water. However, none of these studies dealt with thin reservoirs containing relatively thick bottom water

regions and/or a gas zone. For this study a "thin heavy oil reservoir" was considered to be a heavy oil formation with a thickness of less than about 20 meters (65 feet). The prototype reservoir studied in this research is the thin Aberfeldy reservoir which does not have a gas cap and a bottom water layer only exists in parts of the field. However, the versatility of the equipment used in this research allows one to create a bottom water layer and/or a gas cap in the model of the Aberfeldy reservoir.

Prats¹ modelled the Peace River reservoir, which is characterized by a large oil saturation (45%) in the bottom water layer. In the experiments, steam was injected into the bottom water, increasing the pressure in the reservoir in an attempt to heat the bottom water zone. This procedure enabled the overlying, highly viscous oil zone (65% oil saturation) to be mobilized by the heating effects of the bottom water zone. Due to the relatively high oil saturation in the water zone, the initial injection of steam into this zone resulted in a significant amount of oil being produced which increased the economic attractiveness of the recovery process. To further improve oil recovery, steam was injected directly into the oil zone once the oil saturation in this region was reduced to a predetermined value. The Wabasca reservoir examined by Huygen and Lowry² and the Cold Lake reservoir studied by Pursley³ were both characterized by relatively thin bottom water layers. These investigations therefore do not provide a reasonable representation of Aberfeldy type thin reservoirs. Other than the study performed by Doscher and Ghassemi⁴, little work has been done on steamflooding thin oil reservoirs such as the Aberfeldy.

A study by Kasraie and Farouq Ali⁵ further discussed the application of thermal recovery techniques to "marginal" heavy oil reservoirs. Such reservoirs are defined to have one or more of the following characteristics: thin formation (less than 6 metres), bottom water, gas cap or very high oil viscosity (over 10 Pa.s). Thermal recovery applications under such conditions depend strongly on the extent of bottom water, oil viscosity, vertical permeability, oil saturation and fluid injection rate. Vertical permeability was found to be an important factor in such reservoirs, since even a limited barrier between the oil and water zones would drastically reduce the tendency of the steam to channel down into the water layer. Therefore any shale breaks, silt zones or other heterogeneities at the base of the oil sand would serve to improve the oil recovery performance. Also the implementation of high tem-

perature polymers, foams or additives, such as solvents, may also help to divert the steam away from the bottom water.

Dispersion and Diffusion of Solvents in a Porous Medium

A review of diffusion and dispersion in porous medium has been presented by Perkins and Johnston⁶ and many other authors. Dispersion is defined as the mixing of solvent and oil in a porous medium caused by uneven fluid flow or concentration gradients resulting from fluid flow. Dispersion can occur in the longitudinal direction (direction of gross fluid flow) or transversely (perpendicular to gross fluid flow direction). Along with dispersion and diffusion, imbibition plays an important role in oil recovery during a solvent and/or steam injection process.

Incorporation of Solvent Injection into Thermal Recovery Methods.

Alikhan and Farouq Ali⁸ investigated a recovery process, which incorporated miscible displacement with hot waterflooding. The recovery process involved introducing a small slug of a light hydrocarbon prior to the injection of one-half pore volume of hot water followed by a conventional cold waterflood. Results indicated that pre-injection of the light hydrocarbon slug preceding the waterflood led to a greater oil recovery than that obtained for a conventional waterflood. It was found that the overall oil recovery by this technique was dependent on oil viscosity, light hydrocarbon slug viscosity and the injection rate. The process was also found to be more effective when the reservoir had been previously waterflooded as opposed to a connate water saturation initially existing in the formation. Solvent recovery was found to be higher if a higher initial oil saturation existed, than if residual oil was present.

In studying the application of solvent slugs in thermal operations Farouq Ali⁹ investigated the change in phase behavior characteristics due to an increase in temperature of the fluids involved in a solvent/steam recovery process. It was concluded that at elevated temperatures the overall phase behavior of a typical alcohol-brine system would shift in such a direction as to make displacement of oil by alcohol more efficient. This could be achieved by injecting a small alcohol or solvent slug ahead of a steamflood. A study by Pirela and Farouq Ali¹⁰ investi-

gated the ternary phase behavior of solvent-oil-water systems at low temperatures. An increase in the temperature of the system resulted in an increase in the miscibility of the system, which was found to be advantageous from the standpoint of oil recovery.

Experiments conducted by Ozen and Farouq Ali¹¹ using linear consolidated cores under isothermal conditions revealed that a steam drive could be an effective technique for recovering the residual oil after a waterflood. They also found that the introduction of a small slug of light hydrocarbon (naphtha) preceding steam injection improved the overall oil recovery.

Hernández and Farouq Ali¹² used a one-dimensional model (linear) to examine the use of solvent injection to form a channel through the tar sand, connecting the injection and production wells prior to the injection of steam into the tar sand. Result of the study indicated that the injection of a solvent slug preceding steam injection created improved steam injectivity, leading to a higher overall recovery. It was also noted that the smaller solvent slugs aided in forming a channel into the tar sand for the steam, whereas the larger solvent slugs caused a permeability block which inhibited steam flow.

Snyder and Farouq Ali¹³ proposed the use of solvents as a means of developing flow channels in a tight tar sand to provide the initial flow paths for the injected steam. Specifically, the recovery efficiency of naphtha injection into a two-dimensional homogeneous tar sand pack at various injection rates, the effectiveness of gravity segregation and conductive heating in tar packs with a highly permeable channel were investigated. It was found that during steam injection the steam action was concentrated around the inlet and did not directly contact the bulk of the pack, and therefore naphtha injection prior to steam injection in a homogeneous pack was highly effective in opening a steam flow path. Once created, it allowed the steam to become more concentrated towards the production outlet resulting in improved overall oil recovery.

Farouq Ali and Abad¹⁴ studied the use of solvents in combination with steam using a three-dimensional elemental model. They found that the type of solvent, the volume of solvent slug, and the placement of the solvent in the tar sand pack determined the bitumen recovery, and that smaller solvent slugs were more effective than larger slugs, with an optimum combination of solvent and steam slug.

A study performed by Farouq Ali, Look Yee, Cordero and Figueroa¹⁵ reported comparisons of base steamfloods and solvent-steamfloods showing that the solvent-steamfloods did improve oil recovery. It was also determined in the study that the injected solvent spread over a large area by viscous fingering if the injection rate was high while if the rate was low the solvent essentially diffused into the bitumen and was largely confined to the immediate vicinity of the injection well.

In an economic evaluation of solvent/steam stimulation Dosche, Ershaghi, Herzberg and Gourene¹⁶ suggested that by reducing the viscosity of crude oil before contact with steam by use of a solvent, the overall steam requirement to achieve the same recovery without solvent might be reduced. The authors also suggested that solvent should be used in combination with steam to achieve specific advantages in steam drive operation such as establishing or increasing conductivity between injection and production wells or increasing sweep efficiency.

Redford and McKay¹⁷ found that the use of a solvent in a steam process may reduce the residual saturation in the water-swept areas of the reservoir and thus improve the overall oil recovery. For solvents which are mixed hydrocarbons the more volatile additive (light end) may act as a drive agent while the less volatile (heavier ends) one may act as a viscosity-reducing agent during the pressure depletion portion of the cycle which further improved recovery. Redford¹⁸ reported that the use of naphtha in combination with steam improved oil recovery by reducing bitumen viscosity and thereby improving recovery in the water-swept portions of the reservoir, thus making more efficient use of the drive energy provided by the steam.

A comprehensive study carried out by Alikhan and Farouq Ali¹⁹ investigated a combination of three different processes for the recovery of light and relatively viscous oils, using two approaches: injection of a slug of a light hydrocarbon miscible with the viscous oil, followed by the injection of hot water in one series of experiments, and a steam slug followed by the injection of hot water in another series, each of which was then driven by water. Essentially the mechanism of the process was a combination of miscible displacement, hot waterflooding and steamflooding. The process was designed for a high thermal efficiency utilizing the maximum amount of heat injected. Conclusions drawn from the investigation suggested that the solvent slug injected prior to the hot water or steam slug in a sandpack improved oil recovery as compared to a straight hot water or steam slug.

run. The viscosity was further reduced by the heat from the injected hot water or steam slug, which led to an improvement in the mobility ratio and hence an improvement in the displacement efficiency. A large proportion of the light hydrocarbon slug was recovered by the steam distillation effect.

DISCUSSION OF THE RESULTS

Presentation of the Results

The emphasis of this study was on the use of a small amount of solvent with steam in an attempt to improve the steamflood efficiency. The purpose of using solvents in combination with steam was to increase steam injectivity in the oil zone, and create an initial flow path in the oil layer to divert the steam partially from the underlying water. Another series of experiments involved using other recovery strategies in an attempt to improve steamflood recoveries from reservoirs with thin bottom water zones.

Table 1 lists the pertinent values and results for all the experiments conducted in this investigation. The first group of runs consisted of base experiments which were compared with other experiments in order to observe the effects of different parameters such as solvent injection, solvent slug size, bottom water thickness, gas injection, injection-production interval locations and the use of alternative recovery schemes. These base experiments involved a continuous solvent flood in a homogeneous model, a solvent-steamflood in a homogeneous model, and a steamflood with prior gas injection in a bottom model.

Steamflood vs. Solvent-Steamflood Process

During a steamflood, steam is injected into the injection well resulting in the creation of a steam zone which expands radially outward from the injector into the reservoir as more steam is injected. The hot condensate leaving the steam zone creates a hot waterflood in front of the steam zone. The steam zone, which is at an approximately constant temperature, is the most essential part of a steamflood. Oil in this region is highly mobilized by the heat and is displaced by the gas drive effect of steam. Also the thermal expansion of oil further mobilizes

lizes the oil, and steam distillation of lighter fractions of the oil helps to lower the oil saturation as well.

The mobilized oil is displaced and banked up ahead of the steam zone in the condensate region. Before the steam invades the oil region ahead of the steam zone, the undisturbed oil zone has already been swept by the cold condensate and then the hot condensate. In essence, the advancing steam zone contacts the same oil saturation, whether the formation is previously waterflooded or not. An illustration of the different regions that exist in the reservoir during a steamflood is provided in Figure 1.

Excellent areal coverage is usually obtained during a steamflood due to the gravity segregation of the steam which causes the steam to rise up through the formation. It can, however, limit vertical sweep in thick reservoirs.

The efficiency of a steamflood process is strongly dependent on formation thickness, steam quality, steam temperature and the presence of bottom water, since these factors determine the rate of growth of the steam zone. The presence of a bottom water layer in a thin heavy oil formation is undesirable since it provides a highly conductive flow path for the injected steam to override the oil layer. This lowers the thermal efficiency of a steamflood because a majority of the steam heat is scavenged by the underlying water.

The solvent-steamflood process is quite similar in nature to a steamflood except that a small slug of solvent is injected into the formation prior to steamflooding. The injected solvent channels directly into the oil region which forms an initial flow path for the steam. Therefore the heating effect of the steam can be more effectively utilized to mobilize and displace the oil in the reservoir. A schematic diagram of the solvent-steamflood process is given in Figure 2.

Thin heavy oil formations, with underlying water are considered to be uneconomic for a conventional steamflood for reasons discussed previously. Therefore the purpose of using solvents in combination with a steamflood is to improve steam injectivity in the oil zone, and create an initial flow path in the oil layer in order to divert the steam partially from the underlying water.

Typical Steamflood History in a Bottom Water Reservoir

To obtain a better understanding of the production history of a typical steamflood in a bottom water formation, consider Run 39;

which consisted of a steamflood in a bottom water model. In this run, the bottom water layer thickness was 12.5% of the gross model thickness, i. e. one-eighth of the model thickness.

Result of Run 39 suggested that steam preferentially flowed underneath the oil layer into the more conductive bottom water region due to lower steam injectivity of the oil layer above. Therefore, a majority of the steam heat was channelled into the underlying water zone, which inhibited the formation of a pronounced steam zone and oil bank in the model, and resulted in an unstable steam displacement of the oil and thus a poor oil recovery. The results of this run enable one to achieve a better idea of what to expect during a continuous steamflood of a bottom water formation.

Base Experiments for Comparison Purposes

A range of base experiments were carried out during the research. The data collected from these base runs were used to determine the injection properties of the solvent in the oil-saturated model. The results of the base experiments were also compared with later experiments to determine the effects of solvent injection rate, solvent slug size, bottom water thickness, gas injection, injection-production interval location and a physical barrier on oil recovery, and thermal efficiency of a steamflood process implemented in a thin heavy oil formation, with underlying water.

Continuous Solvent Flood

Run 40 involved flooding a oil-saturated, homogeneous model with the chosen solvent (Heavy Virgin Naphtha). This first base run was a continuous solvent flood in the homogeneous (i.e. no bottom water) model. The intention of the solvent flood was to estimate the injection behavior of the solvent in the homogeneous model during the experiment. It appeared that the solvent channelled through the oil immediately upon injection and continued to do so throughout the experiment. This type of injection behavior of the solvent was desirable in the context of a steamflood, because the solvent channels formed would aid in increasing the injectivity of steam into the oil during a steam injection process. The higher steam injectivity could allow a steam injection process to be more thermally efficient since less

of the heat would be lost to such heat sinks as overburden, underburden, adjacent formations and bottom water zones. Therefore the injected steam could be utilized more effectively in mobilizing and displacing the in-place oil.

Solvent-Steamflood

Runs 44, 45 and 46 involved injecting a small solvent slug into an oil-saturated, homogeneous model prior to a continuous steamflood. The purpose of the solvent slug prior to steam injections was to create solvent channels into the oil region through which the injected steam could more easily penetrate and thus, more efficiently mobilize the oil. Results indicated that more oil was mobilized and displaced, therefore a larger oil bank (actually solvent and oil) formed and a more stable steam displacement resulted. The greater stability of the steam injection process resulted in a prolonged time until steam breakthrough and an improved overall oil recovery.

The solvent-steamflood process did not appear to be as economically attractive as a conventional steamflood performed in a homogeneous model. However, in the case of a heavy oil formation with bottom water and displaying a very low steam injectivity the implementation of solvent injection would help to raise steam injectivity. This would make steam penetration more extensive in the oil and therefore increase recovery compared to a conventional steamflood.

Effect of Solvent Slug Size on Oil Recovery by a Steamflood

It was desired to determine the effect of solvent slug size on oil recovery from a solvent-steamflood process. By determining the effect of solvent slug size, an optimal slug size might be estimated. As reported by Alikhan¹⁹ the use of a 10% solvent slug prior to steam injection provided the highest oil recovery compared to the 5% and 15% solvent slug runs. A comparison plot (Figure 3) of the recovery curves for the three experiments indicates that Run 45 had the best recovery with Run 67 second and Run 66 having the lowest recovery. From the results of the three experiments it appeared that the 10% solvent slug run allowed a more stable displacement to occur in the model and thus a greater recovery. Run 45 (10% slug) achieved the optimal balance between oil viscosity reduction and channelling.

which means that some of the oil does not contact the solvent. In the case of the 5% solvent slug experiment, less solvent channelling existed in the oil, thus less extensive steam penetration of the oil, consequently less oil was mobilized. For the 15% solvent slug run the larger solvent slug used created larger solvent channels in the model which allowed the steam to flow more directly from the injection to production well and therefore more of the steam was partially diverted away from heating the oil than in Run 45. It was concluded from the results of Runs 66, 67 and 45 that there exists an optimal slug size of approximately 10% of the model pore volume which maximizes the oil recovered by a solvent-steamflood process.

Effect of Bottom Water Thickness on Solvent-Steamflood Response

The purpose of the initial solvent injection into the oil layer prior to steamflooding was to create a pathway in the oil layer for the steam to follow in an attempt to improve the oil recovery compared to conventional steamflooding a bottom water formation.

Runs 49, 50, 51, 53 and 54 all involved injecting 0.10 pore volume of solvent (Heavy Virgin Naptha) followed by a continuous steamflood of a model containing a bottom water layer. The only difference between the five bottom water experiments was that the bottom water thickness varied for each run. Bottom water thickness was altered each run so as to investigate its effect on the oil recovery.

The bottom water thicknesses for Runs 49 (8.8% of gross model thickness), 50 (10.2% of gross model thickness) and 54 (12.2% of gross model thickness) were about the same, whereas Run 51 (26.2% of gross model thickness) and 53 (15.2% of gross model thickness) had much thicker bottom water layers. The injection well for the model was situated so to inject fluids into the upper portion of the model. This was to ensure that the solvent and steam would not flow directly into the bottom water layer and override the oil immediately upon injection.

The overall oil recoveries for Runs 49 (23.3% OOIP), 50 (25.4% OOIP), 51 (14.3% OOIP), 53 (19.0% OOIP) and 54 (22.6% OOIP) illustrate that bottom water can significantly reduce the amount of oil recovered by a solvent-steamflood. The effect of the bottom water on solvent and steam injection resulted in a considerably lower oil recovery that obtained with a solvent-steamflood implemented on a homogeneous reservoir. Results of Runs 49, 50, 51, 53 and 54 confirm that the use of a solvent slug assisted in improving the overall oil recovery.

recovery by partially diverting the steam away from the bottom water and into the oil layer during the initial stages of the steamflood. It was also noted that the bottom water had a more detrimental effect on the overall oil recovery as it increased in thickness. Figure 4, a plot of oil recovery after two pore volumes injected versus bottom water thickness for the five experiments as well as Run 46 (solvent-steamflood without bottom water), demonstrates the effect varying bottom water thickness has on overall oil recovery. It is seen that for thicknesses less than approximately 10% of the gross model thickness, the oil recovery due to the solvent-steamflood process is close to that obtained by solvent-steamfloods implemented in homogeneous models. For bottom water thicknesses greater than about 10% of the total model thickness the overall oil recovery of the solvent-steamflood process is greatly reduced. The experimental results suggest that the injection of a solvent slug prior to steamflooding a bottom water reservoir could improve the overall oil recovery up until a limiting bottom water thickness is reached. Based upon Figure 4, the limiting bottom water thickness is estimated to be somewhere between 25 and 30% of the total model thickness. It is concluded that as the bottom water thickness increases in the model the oil recovery is decreased until a limiting bottom water thickness is reached, above which the use of a solvent slug does not significantly improve the oil recovery.

One of the major objectives of this study was to investigate the use of solvents in combination with steam as a recovery method for marginal heavy oil reservoirs containing bottom water and/or a gas cap. Solvent injection into the oil layer during the initial period of the runs created a temporary preferential path for the steam to follow, preventing the steam from immediately channelling into the bottom water. The steam progressed through the oil layer for a short period of time until it finally moved downward and advanced through the bottom water section, leading to a drop in heating efficiency, and a severe drop in the overall oil recovery.

Comparison of the results of Runs 49, 50 and 54 with previous continuous steamfloods (Run 32, 33 & 39) carried out with similar bottom water (BW) thicknesses, revealed that the solvent slug injection prior to steamflooding partially alleviated the effect of bottom water and resulted in improved oil recovery. Due to partial diversion of the steam into the solvent channels in the oil region the steam displacement achieved was more stable, causing a delayed and more pronounced steam breakthrough to occur at the production well. In

the case of a conventional steamflood, the bottom water had a greater and more immediate effect on steam displacement resulting in a much less stable displacement. This led to earlier and less distinct steam breakthrough at the producer. Oil recovery results for Runs 32 (BW = 2.3%), 33 (BW = 4.0%) and 39 (BW = 12.5%) were 22.8%, 22.9% and 16.9% of the original oil in place, respectively. These recoveries were appreciably less than the recoveries yielded by Runs 49 (23.3%), 50 (25.4%), 53 (19.0%) and 54 (22.6%). In the case of Run 51, there did not seem to be an improvement in the oil recovery compared to the Runs 32, 33 and 39. Because of the extensive bottom water layer in Run 51 the steam was not able to flow through the oil layer for as long as in Runs 49, 50, 53 and 54 resulting in a considerable decline in the oil recovery of Run 51. Comparing the results of the two different types of experiments (i.e. steamflood vs. solvent-steamflood) revealed that the solvent-steamflood does exhibit an improved oil recovery capability from bottom water formations in relation to a conventional steamflood. A cross plot of the recovery curves for Runs 39 and 54 is provided in Figure 5 which compares the effectiveness of a solvent-steamflood process as opposed to a steamflood in similar bottom water formations. The difference in the initial behavior of these two curves demonstrates the effectiveness of the solvent slug. The recovery curve for Run 54 in the primary stages of the run rises sharply compared to the recovery curve of Run 39. This was due to solvent channelling in Run 54 allowing the steam to penetrate the oil zone more easily, which increased the stability of the steam displacement of oil in the model, and resulted in more oil being mobilized and subsequently recovered. Figure 5 illustrates the increased oil recovery potential of the solvent-steamflood process over a conventional steamflood in bottom water formations.

It is concluded from the results of Runs 32, 33, 39, 49, 50, 51, 53 and 54 that the solvent slug assisted in improving the overall oil recovery in bottom water formations by partially diverting the steam away from the bottom water zone during the initial stages of the steamflood.

Role of Gas Injection in Steamflooding

Gas Injection with Solvent and Steam Injection

By injecting a small value of inert gas before performing a solvent-steamflood it is believed that a flow channel can be created which would divert the injected solvent and steam away from the bottom

water region and into the oil zone. The process of gas injection in combination with a solvent-steamflood was first performed in a homogeneous model. Run 55 and 56 consisted of creating a gas cap in a homogeneous model prior to a solvent-steamflood which used a 10% pore volume slug of solvent. The initial gas saturation in the model for the two runs was 0.6%.

Gas Injection Prior to Solvent and Steam Injection with Bottom Water

Runs 58, 59 and 62 involved performing a solvent-steamflood on a bottom water/gas cap reservoir. The bottom water thickness for Runs 58, 59 and 62 were 9.8%, 13.6% and 12.0% of the gross model thickness, respectively, and the initial gas saturations were 0.6% (Run 58), 0.6% (Run 59) and 0.3% (Run 62), averaged over the entire zone. It is estimated that the gas segregated into a thin layer above the oil zone, given a critical gas saturation of zero, in the time involved.

Figure 6 provides a comparison of the recovery curves for a solvent-steamflood (Run 50) and a solvent-steamflood with previous gas injection (Run 58) in bottom water models. The bottom water thicknesses were 10.2% and 9.8%, respectively in these runs. It is evident from Figure 6 that Run 50 (solvent-steamflood) achieved a considerably greater oil recovery than Run 58 (gas injection prior to solvent-steamflood). The main difference between the curves occurred during the initial stages of the two experiments. Run 50 had a more drastic initial increase in recovery (25.4% OOIP) compared to Run 58 (18.2%) due to the solvent and oil more effectively penetrating the oil zone and creating more stable steam displacement of oil during Run 50. Run 58 had a less pronounced solvent oil invasion in the oil region since more solvent and oil flowed over top of the oil zone through the gas saturation channel formed by the previous gas injection. Steam breakthrough was earlier and less distinct for Run 58 due to the existence of a less stable displacement of oil caused by the gas channel.

A gas cap in a reservoir can be helpful or detrimental to the effectiveness of a steam injection process depending on certain characteristics of the reservoir such as heat loss, reservoir thickness, bottom water thickness and the gas cap size. During the steamflood of a bottom water reservoir the gas cap allowed the steam to remain in the upper portion of the formation away from the bottom water, thus heating and mobilizing the inplace oil from above. How effectively the oil was

mobilized from above depends on the magnitude of the heat lost to the overburden, adjacent formations and the bottom water zone. However, in the case of the solvent-steamflood process the gas cap enable the solvent to flow over the top of the oil zone. Overriding of the oil by the solvent caused fewer flow channels to form in the oil layer, which hindered the penetration of the oil layer by steam. Consequently, less oil was mobilized by the steam resulting in a decline in the overall recovery of a solvent-steamflood process as compared to its implementation in a heavy oil reservoir with bottom water but no gas cap or gas channel.

Effect of Injection - Production Interval Locations

The effect of injection-production interval locations on the success of the solvent-steamflood process in bottom water reservoir was found to be very important. By optimizing the injection-production interval positions the injected solvent and steam could be utilized effectively to recover the in-place oil.

A comparison of the recovery curves from the two experiments (Run 49 and 50), provided in Figure 7, indicates that the most effective injection-production intervals appeared to be those used in Run 50 where injection was into the upper half and production was from the entire model thickness. The injection interval location for Run 50 permitted more efficient use of the injected solvent and steam, by directing these fluids into the oil zone and away from the bottom water, thus yielding a higher overall oil recovery. However, for Run 49, more solvent and steam were lost to the underlying water zone, making this solvent-steamflood process less efficient than the solvent-steamflood conducted in Run 50.

Effectiveness of Waterflooding Prior to Solvent and Steam Injection

Another objective of the research conducted was to determine the effectiveness of the solvent-steamflood process as an enhanced recovery technique. In Runs 47 and 48 a solvent-steamflood was conducted following a waterflood of a homogeneous model.

The overall oil recoveries for Runs 47 (33.5% OOIP) and 48 (35.5%) were higher than the recoveries obtained from the conventional steamfloods of the homogeneous model performed in Runs 26 (31.8%) and 27 (32.2%) as reported by Proctor, George and Farouq

Ali¹⁹. The recoveries for the solvent-steamfloods of a homogeneous models (Runs 44 (27.1%), 45 (30.0%) and 46 (27.7%)), reported in this study also indicate that Runs 47 and 48 yielded a greater overall oil recovery. The oil recoveries for the waterflood cases (Runs 47 and 48) were higher because the solvent was able to blend with in-place oil more thoroughly than during the oil saturated experiments (Runs 26, 27, 44, 45 and 46). Alikhan¹⁹ also stated that for a high initial oil saturation the solvent slug is displaced as efficiently as the in-place oil, thus the advantage of using the solvent is partially lost and the oil recovery is diminished. However, for a waterflooded porous medium the solvent is able to mix more extensively with the oil allowing the injected steam to contact an higher saturation of the solvent slug material leading to improved oil recovery.

Comparing the oil recoveries for Runs 47 and 48 with those for the previous experiments using a homogeneous model, it was noted that Runs 47 and 48 yielded the highest oil recovery of all the experiments performed using a homogeneous model saturated with oil. The information obtained from Runs 47 and 48 agrees closely with the results recorded by Alikhan¹⁹. Performing solvent-steamfloods on waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery technique, but will depend strongly on the initial oil in-place.

CONCLUSIONS

Based upon the results the research the following conclusion were reached:

1. The solvent-steamflood process exhibits an improved oil recovery capability from a bottom water formation as compared a conventional steamflood in the same type of reservoir for an oil viscosity of about 1000 mP-s.
2. Gas injection prior to a solvent-steamflood of a bottom water formation tends to diminish solvent channelling in the oil, due to the solvent travelling over top of the oil zone, with less steam penetrating the oil layer, with a consequent drop in oil recovery.
3. In the case of a solvent-steamflood process on a bottom water formation, as the bottom water thickness increased in the model, the oil recovery decreased until a limiting bottom water thickness was reached. Above this value (between 25% and 30% of the total formation thickness), the use of a solvent did not significantly improve oil recovery.

4. There seems to be an optimal solvent slug size of approximately 10% of the model pore volume which maximizes the amount of oil recovered by a solvent-steamflood process.

5. Location of the injection interval in the upper portion of the formation (ie. oil zone) permits more efficient use of the injected solvent and steam and increases oil recovery by directing the fluids into the oil zone and away from the bottom water layer, as compared to injection over the entire interval or into the bottom portion of the formation.

6. Conducting solvent-steamfloods of previous waterflooded reservoirs to improve oil recovery shows promise as an enhanced heavy oil recovery scheme.

7. A comparison of the experimental results for a solvent-steamflood, conventional steamflood and gas injection prior to a solvent-steamflood, all conducted in a bottom water model, revealed that the solvent-steamflood technique yielded the highest oil recovery.

Table 1 : List of Experiments

Run No.	Model Type	Type of Inj. & Prod. Process	Intervals	Porosity (%)	Soi (%)	Swi (%)	Sgi (%)	Bottom Water (%)	Slug Size Cum. Rec. Solv. Rec. Cum. P.V. (% P.V.)	(% OOLP) *	(%) *	Injected
39	BWM	SF	IE-PU	37.1	86.0	14.0	---	12.5	---	16.8	---	1.78
40	HM	CSI	IE-PU	33.7	92.5	7.5	---	---	---	26.8	89.5	2.25
41	HM	USR	IE-PU	---	---	---	---	---	---	---	---	---
42	HM	USR	IE-PU	---	---	---	---	---	---	---	---	---
43	HM	USR	IE-PU	---	---	---	---	---	---	---	---	---
44	HM	SSF	IE-PU	33.7	92.9	7.1	---	---	10.0	27.1	70.4	2.33
45	HM	SSF	IE-PU	34.1	92.0	8.0	---	---	10.0	30.0	71.2	2.59
46	HM	SSF	IE-PU	38.7	80.9	19.1	---	---	10.0	27.7	33.1	2.07
47A	HM	WF	IE-PU	33.6	93.0	7.0	---	---	---	19.1	---	1.54
47B	HM	SSF	IE-PU	33.6	75.3	24.7	---	---	10.0	33.5	44.9	2.03
48A	HM	WF	IE-PU	33.4	92.7	7.3	---	---	---	19.8	---	1.69
48B	HM	SSF	IE-PU	33.4	74.3	25.7	---	---	10.0	33.5	58.9	2.25
49	BWM	SSF	IE-PU	37.0	86.7	13.3	---	8.8	10.0	23.3	84.6	2.13
50	BWM	SSF	IU-PE	35.8	91.2	8.8	---	10.2	10.0	25.4	88.5	2.26
51	BWM	SSF	IU-PE	37.7	66.9	33.1	---	26.2	10.0	14.3	40.8	2.05
52	BWM	USR	IU-PE	---	---	---	---	---	---	---	---	---
53	BWM	SSF	IU-PE	36.5	76.2	23.8	---	15.2	10.0	19.0	54.4	2.16
54	BWM	SSF	IU-PE	36.1	91.0	9.0	---	12.2	10.0	22.6	89.8	2.39
55	HM	GISSF	IU-PE	34.3	90.3	9.1	0.6	---	10.0	26.8	87.7	2.37
56	HM	GISSF	IU-PE	33.6	93.0	6.3	0.6	---	10.0	27.0	90.9	2.43
57	BWM	USR	IU-PE	---	---	---	---	---	---	---	---	---
58	BWM	GISSF	IU-PE	35.6	86.4	13.0	0.6	9.8	10.0	18.2	88.6	2.27

Table 1 : Continued

Run No.	Model Type	Type of Inj. & Prod. Process	Intervals	Porosity (%)	Soi (%)	Swi (%)	Sgi (%)	Bottom Water (%)	Slug Size Cum. Rec. Solv. Rec. Cum. P.V. (% P.V.)	(% OIP) *	Injected	
59	BWM	GISSF	IU - PE	35.7	85.3	14.1	0.6	13.6	10.0	24.7	96.7	2.30
60	BWM	GISF	IU - PE	35.9	76.3	23.4	0.3	17.6	---	13.6	---	2.31
61	BWM	GISF	IU - PE	36.0	83.5	16.2	0.4	12.1	---	19.5	---	2.30
62	BWM	GISSF	IU - PE	36.3	83.4	16.3	0.3	12.0	10.0	20.0	94.7	2.29
63	BWM	SFPBW	IU - PE	36.3	77.5	22.5	---	15.4	---	17.0	---	2.26
64	BWM	SFPBW	IU - PE	36.7	87.5	12.5	---	9.9	---	22.0	---	2.27
65	BWM	SSF	IU - PE	36.1	73.4	26.6	---	19.6	20.0	19.8	73.0	2.29
66	HM	SSF	IU - PE	33.5	93.3	6.7	---	---	5.0	24.2	91.4	2.59
67	HM	SSF	IU - PE	33.5	92.5	7.5	---	---	15.0	25.9	97.0	2.43

HM	- Homogeneous Model	GISSF	- Gas Injection Prior to Solvent-Steamflood
BWM	- Bottom Water Model	SFPBW	- Steamflood with Partial Bottom Water Barrier
SF	- Continuous Steamflood	USR	- Unsuccessful Run
CSI	- Continuous Solvent Injection	IU	- Injection Into Upper Portion of Model
SF	- Steamflood	IE	- Injection Over Entire Model Interval
SSF	- Solvent-Steamflood	PU	- Production From Upper Portion of Model
WF	- Waterflood	PE	- Production From Entire Model Interval
GISF	- Gas Injection Prior to Steamflood		

* - The Cumulative Oil and Solvent Recoveries listed in the table correspond to the Cumulative Pore Volume Injected which is provided in the last column of this table.

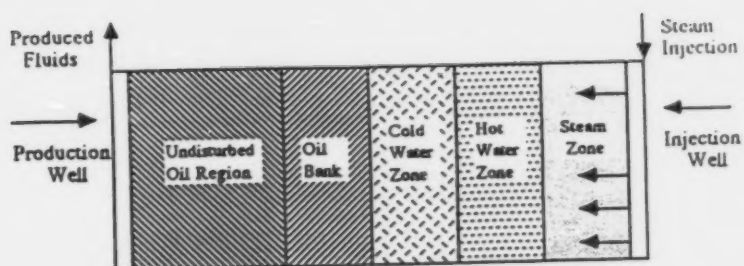


Figure 1 : Schematic Diagram of a Steamflood Process

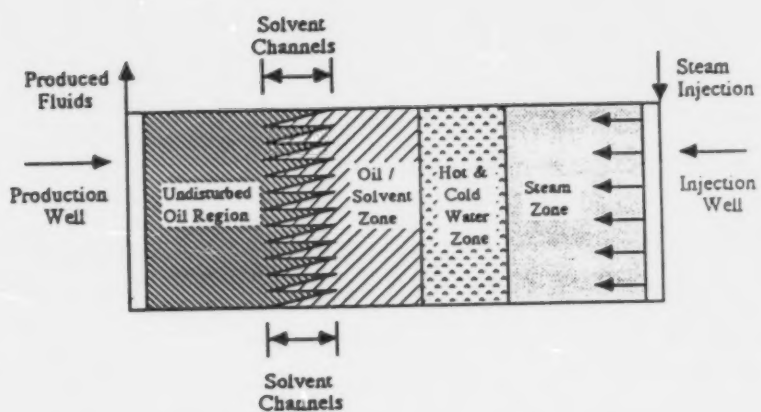


Figure 2 : Schematic Diagram of Solvent - Steamflood Process

Figure 3 :Comparison of the Effect of Solvent Slug Size on Solvent-Steamflood Recoveries for Runs 45, 66 & 67

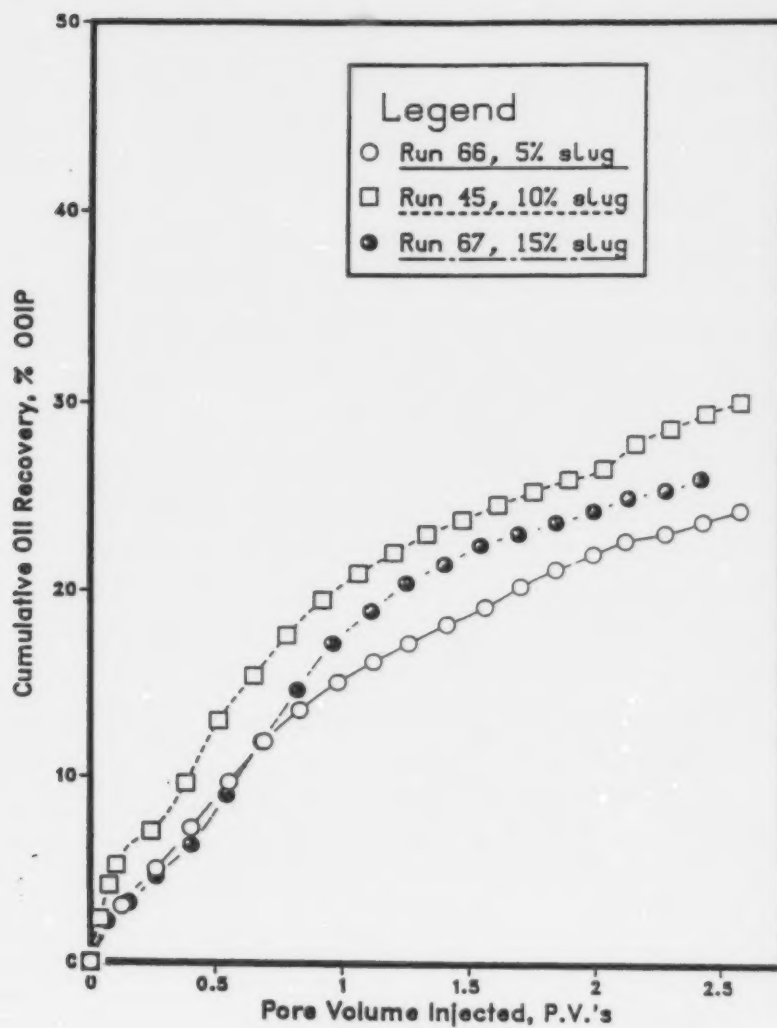


Figure 4 :Total Oil Recovery versus Bottom Water Thickness For Solvent-Steamfloods

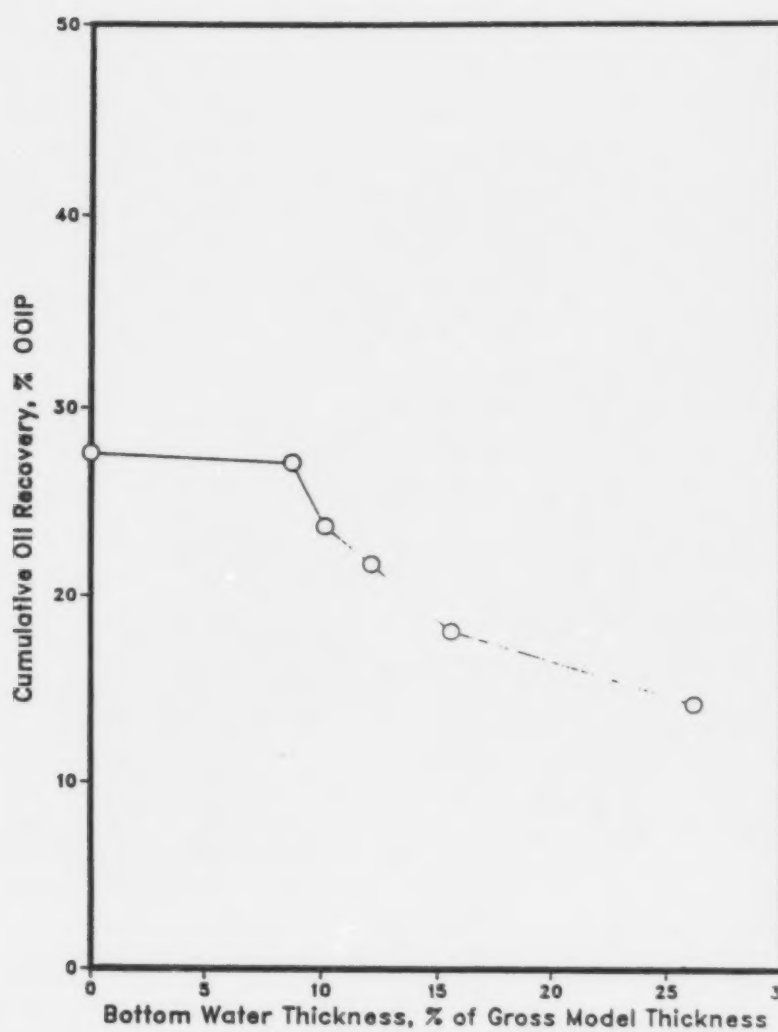


Figure 5 : Comparison of Steamflood Run 39 & Solvent-Steamflood Run Recoveries Performed in a Bottom Water Model

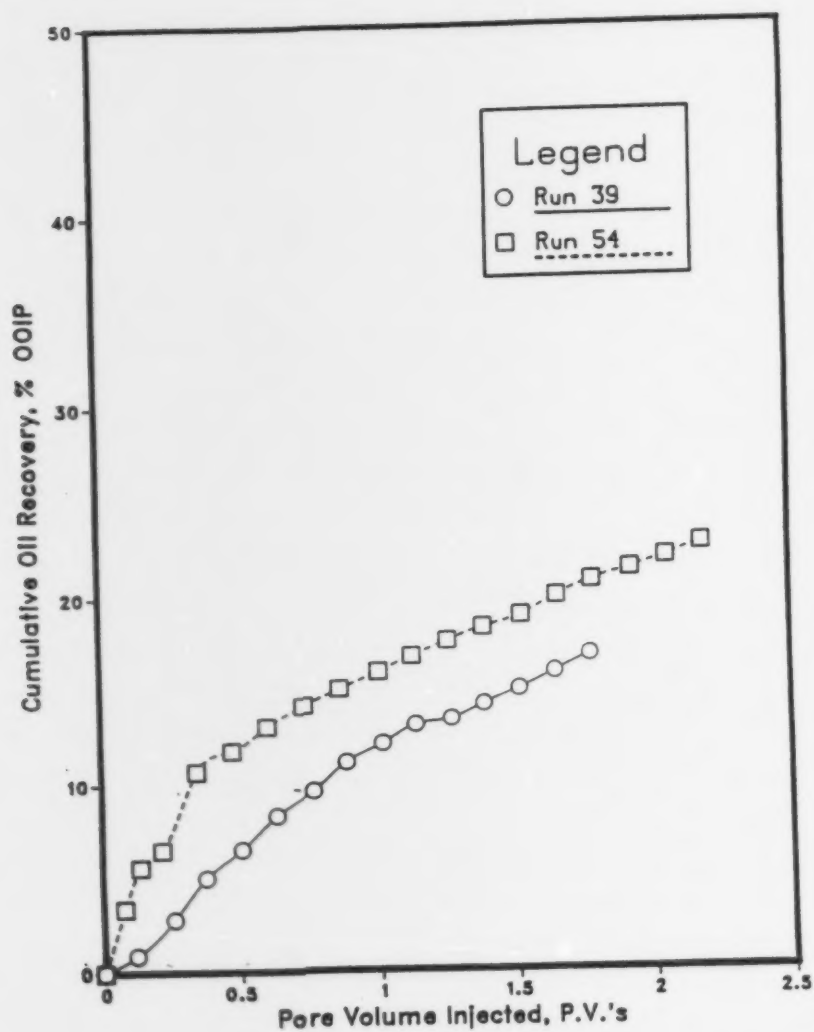


Figure 6 :Comparison of Solvent-Steamflood Run 50 & Gas Injection Prior to Solvent-Steamflood Run 58 Recoveries Performed in a Bottom Water Mo

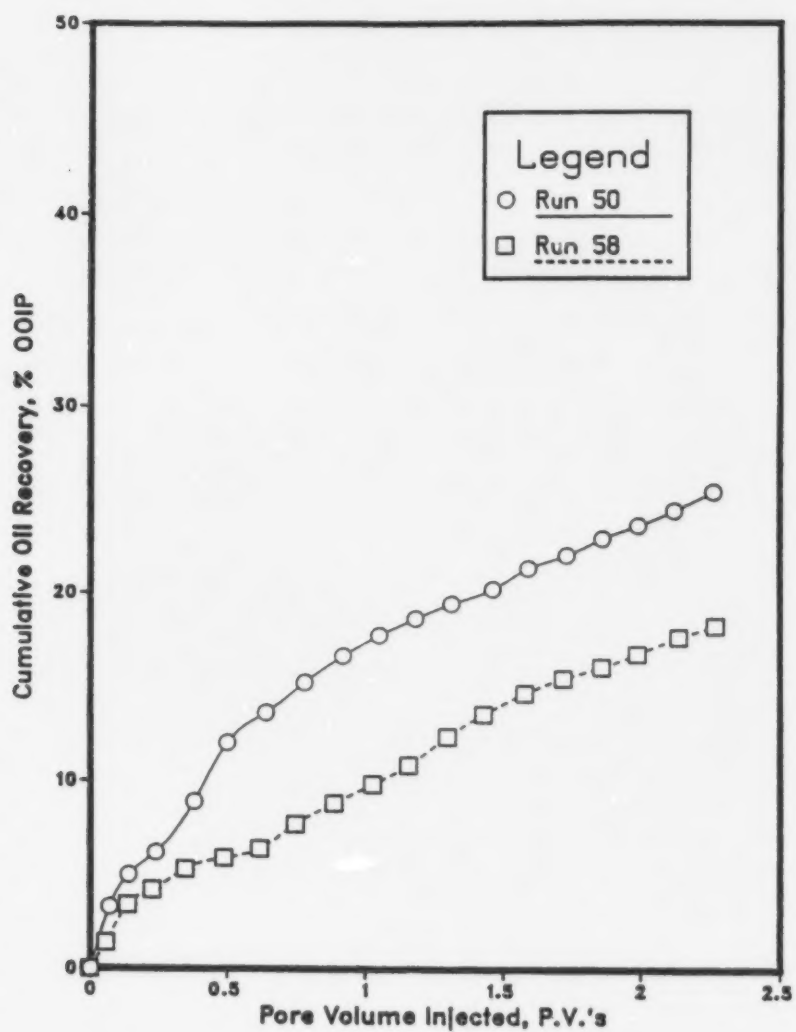
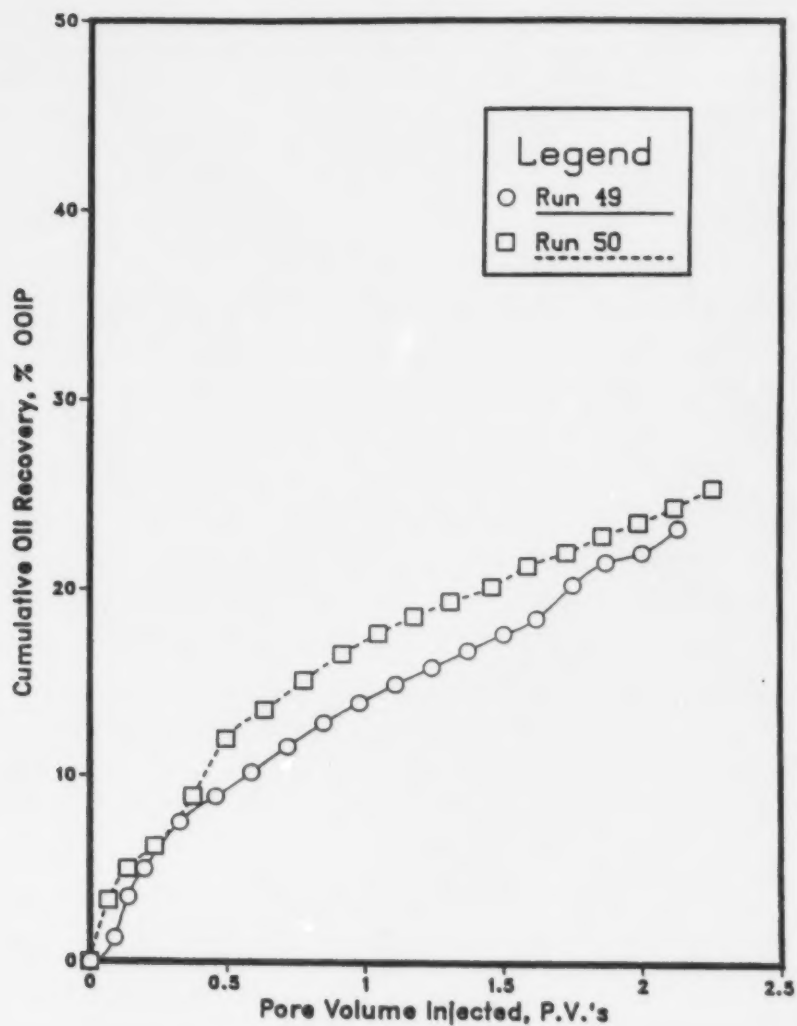


Figure 7 : Comparison of the Effect of Inj.-Prod. Interval Location For Runs 49, Inj-Entire & Prod-Upper, & Run 50, Inj-Upper & Prod-Ei



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